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Environmental Considerations of Selected Energy Conserving Manufacturing Process Options: Volume VII. Ammonia Industry Report

Arthur D. Little, Inc, Cambridge, Mass.

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ENVIRONMENTAL CONSIDERATIONS OF SELECTED ENERGY CONSERVING MANUFACTURING PROCESS OPTIONS: Vol. VII. Ammonia Industry Report

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16. ABSTRACT

This study assesses the likelihood of new process technology and new practices being introduced by energy intensive industries and explores the environmental impacts of such changes.

Specifically, Vol. VII deals with the ammonia industry and analyzes the production of ammonia based on coal gasification and the production of ammonia based on heavy oil gasification in terms of process economics and environmental/energy consequences. Vol. III-XI and Vol. XIII-XV deal with the following industries: iron and steel, petroleum refining, pulp and paper, olefins, aluminum, textiles, cement, glass, chlor-alkali, phosphorus and phosphoric acid, copper, and fertilizers. Vol. I presents the overall summation and identification of research needs and areas of highest overall priority. Vol. II, prepared early in the study, presents and describes the overview of the industries considered and presents the methodology used to select industries.

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ENVIRONMENTAL CONSIDERATIONS OF SELECTED ENERGY CONSERVING MANUFACTURING PROCESS OPTIONS

Volume VII

AMMONIA INDUSTRY REPORT

EPA Contract No. 68-03-2198

Project Officer

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INDUSTRIAL ENVIRONMENTAL RESEARCH LABORATORY
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FOREWORD

When energy and material resources are extracted, processed, converted, and used, the related pollutional impacts on our environment and even on our health often require that new and increasingly more efficient pollution control methods be used. The Industrial Environmental Research Laboratory - Cincinnati (IERL-Ci) assists in developing and demonstrating new and improved methodologies that will meet these needs both efficiently and economically.

This study, consisting of 15 reports, identifies promising industrial processes and practices in 13 energy-intensive industries which, if implemented over the coming 10 to 15 years, could result in more effective utilization of energy resources. The study was carried out to assess the potential environmental/energy impacts of such changes and the adequacy of existing control technology in order to identify potential conflicts with environmental regulations and to alert the Agency to areas where its activities and policies could influence the future choice of alternatives. The results will be used by the EPA's Office of Research and Development to define those areas where existing pollution control technology suffices, where current and anticipated programs adequately address the areas identified by the contractor, and where selected program reorientation seems necessary. Specific data will also be of considerable value to individual researchers as industry background and in decision-making concerning project selection and direction. The Power Technology and Conservation Branch of the Energy Systems-Environmental Control Division should be contacted for additional information on the program.

David G. Stephan
Director
Industrial Environmental Research Laboratory
Cincinnati

EXECUTIVE SUMMARY

Natural gas is the basic feedstock for virtually all ammonia production in the United States. Construction of new ammonia plants to meet demand is becoming increasingly difficult because of the shortage of natural gas. If this shortage persists, the ammonia industry will be forced to implement the use of alternate feedstocks, such as coal and heavy fuel oil, in 50 to 100 percent of new plant construction from 1985 forward, and one or two new plants may even be built prior to that time. Such plants are not commercial in the United States at present and, thus, will constitute a major process change. Also, such plants are likely to have pollution problems significantly greater than present plants. Therefore, we chose to analyze the process options of:

- ammonia production based upon coal gasification; and,
- ammonia production based upon heavy oil gasification.

As a guide for interpreting the energy and pollution effects of changing feedstocks upon the economics of manufacturing ammonia, we have estimated typical investments and operating costs of new plants using natural gas, coal and heavy fuel oil feedstocks, based upon conditions prevailing during March 1975. The coal and heavy oil alternatives are not economically attractive under the conditions chosen for our evaluations in this study. If the price of natural gas to the ammonia industry were to rise from the $0.85 per million Btu (used in this study) to approximately $2.50 per million Btu, the calculated ammonia costs would rise from our estimated $98 per ton of ammonia to $153 per ton. This would change the economic attractiveness of the coal- and heavy oil-based alternatives.

Significant incremental capital investment above that of plants based upon natural gas (which is on the order of $186 per annual ton of ammonia) is involved in the alternative processes, as high as $111 per annual ton of ammonia capacity for the coal alternative and $21 per annual ton for the heavy fuel oil alternative. Incremental production costs of $17 per ton of ammonia, which includes $8.65 per ton for pollution abatement, are expected for the coal alternative. The corresponding incremental cost for the heavy fuel oil alternative is $45 per ton of ammonia, which includes $3.46 for pollution abatement. The investment required for a coal- or heavy oil-based plant is higher than that for one based on natural gas. Nevertheless, when faced with a continuing shortage of natural gas, the industry will have to find other fuel and feedstocks.

The needed pollution control technology will mean an expenditure of energy equivalent to 165,000 Btu per ton of ammonia for the coal alternative, and a 0.5 percent increase in the total energy required for ammonia production. Approximately 125,000 Btu are required for pollution control for the heavy fuel oil alternative, corresponding to a 0.2 percent increase in energy consumption. Thus, the relative incremental fuel use is negligible, while the fuel form savings are significant.

While the environmental impact could be significant for these alternatives, there are no unique problems which will be encountered by new ammonia plants basing production on coal and heavy fuel oil feedstocks. Difficulties will be no greater than those encountered in electric power generation or in industrial boilers fired with these fuels. However, the need to address these difficulties at industrial plants will be a new experience.

This report was submitted in partial fulfillment of contract 68-03-2198 by Arthur D. Little, Inc. under sponsorship of the U.S. Environmental Protection Agency. This report covers a period from June 9, 1975 to January 20, 1976.

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During the course of the study we also had occasion to contact many individuals within industry and trade associations. Where appropriate we have made reference to these contacts within the various reports. Frequently, however, because of the study's emphasis on future developments with comparative assessments of new technology, information given to us was of a confidential nature or was supplied to us with the understanding that it was not to be credited. Therefore, we extend a general thanks to all those whose comments were valuable to us for their interest in and contribution to this study.

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ENGLISH-METRIC (SI) CONVERSION FACTORS

To Convert From	To	Multiply By
Acre	$Metre^2$	4,046
Atmosphere (normal)	Pascal	101,325
Barrel (42 gal)	$Metre^3$	0.1589
British Thermal Unit	Joule	1,055
Centipoise	Pascal-second	0.001
Degree Fahrenheit	Degree Celsius	$t_C^\circ = (t_F^\circ - 32)/1.8$
Degree Rankine	Degree Kelvin	$t_K^\circ = t_R^\circ/1.8$
Foot	Metre	0.3048
$Foot^3$/minute	$Metre^3$/sec	0.0004719
$Foot^3$	$Metre^3$	0.02831
$Foot^2$	$Metre^2$	0.09290
Foot/sec	Metre/sec	0.3048
$Foot^2$/hr	$Metre^2$/sec	0.00002580
Gallon (U.S. liquid)	$Metre^3$	0.003785
Horsepower (550 ft-lbf/sec)	Watt	745.7
Horsepower (electric)	Watt	746.0
Horsepower (metric)	Watt	735.5
Inch	Metre	0.02540
Kilowatt-hour	Joule	3.60×10^6
Litre	$Metre^3$	1.000×10^{-3}
Micron	Metre	1.000×10^{-6}
Mil	Metre	0.00002540
Mile (U.S. statute)	Metre	1,609
Poise	Pascal-second	0.1000
Pound force (avdp)	Newton	4.448
Pound mass (avdp)	Kilogram	0.4536
Ton (assay)	Kilogram	0.02916
Ton (long)	Kilogram	1,016
Ton (metric)	Kilogram	1,000
Ton (short)	Kilogram	907.1
Tonne	Kilogram	1,000

Source: American National Standards Institute, "Standard Metric Practice Guide," March 15, 1973. (ANS72101-1973) (ASTM Designation E380-72)

I. INTRODUCTION

A. BACKGROUND

Industry in the United States purchases about 27 quads* annually, approximately 40% of total national energy usage.** This energy is in the form of feedstocks, chemical reactions, space cooling and heating, process stream heating, and miscellaneous other purposes.

In many industrial sectors energy consumption can be reduced significantly by better "housekeeping" (i.e., shutting off standby furnaces, better thermostat control, elimination of steam and heat leaks, etc.) and greater emphasis on optimization of energy usage. In addition, however, industry can be expected to introduce new industrial practices or processes either to conserve energy or to take advantage of a more readily available or less costly fuel. Such changes in industrial practices may result in changes in air, water or solid waste discharges. The EPA is interested in identifying the pollution loads of such new energy-conserving industrial practices or processes and in determining where additional research, development, or demonstration is needed to characterize and control the effluent streams.

B. CRITERIA FOR INDUSTRY SELECTION

In the first phase of this study we identified industry sectors that have a potential for change, emphasizing those changes which have an environmental/energy impact.

Industries were eliminated from further consideration within this assignment if the only changes that could be envisioned were:

- energy conservation as a result of better policing or "housekeeping,"
- better waste heat utilization,
- fuel switching in steam raising, or
- power generation.

---

*1 quad = 10^{15} Btu

**Purchased electricity valued at an approximate fossil fuel equivalence of 10,500 Btu/kWh.

After discussions with the EPA Project Officer and his advisors, industry sectors were selected for further consideration and ranked using:

- Quantitative criteria based on the gross amount of energy (fossil fuel and electric) purchased by industry sector as found in U.S. Census figures and on information provided from industry sources. The ammonia industry purchased 0.63 quads out of the 12.14 quads purchased in 1971 by the 13 industries selected for study, or 2% of the 27 quads purchased by all industry (see Table I-1).

- Qualitative criteria relating to probability and potential for process change, and the energy and effluent consequences of such changes.

In order to allow for as broad a coverage of technologies as possible, we then reviewed the ranking, eliminating some industries in which the process changes to be studied were similar to those in another industry planned for study. We believe the final ranking resulting from these considerations identifies those industry sectors which show the greatest possibility of energy conservation via process change. Further details on this selection process can be found in the Industry Priority Report prepared under this contract (Volume II).

On the basis of this ranking method, the ammonia industry appeared in fourth place among the 13 industrial sectors listed.

TABLE I-1

SUMMARY OF 1971 ENERGY PURCHASED IN SELECTED INDUSTRY SECTORS

Industry Sector	10^{15} Btu/Yr	SIC Code In Which Industry Found
1. Blast furnaces and steel mills	3.49(1)	3312
2. Petroleum refining	2.96(2)	2911
3. Paper and allied products	1.59	26
4. Olefins	0.984(3)	2818
5. Ammonia	0.63(4)	287
6. Aluminum	0.59	3334
7. Textiles	0.54	22
8. Cement	0.52	3241
9. Glass	0.31	3211, 3221, 3229
10. Alkalies and chlorine	0.24	2812
11. Phosphorus and phosphoric acid production	0.12(5)	2819
12. Primary copper	0.081	3331
13. Fertilizers (excluding ammonia)	0.078	287

(1) Estimate for 1967 reported by FEA Project Independence Blueprint, p. 6-2, USGPO, November 1974.

(2) Includes captive consumption of energy from process byproducts (FEA Project Independence Blueprint)

(3) Olefins only, includes energy of feedstocks: ADL estimates

(4) Amonia feedstock energy included: ADL estimates

(5) ADL estimates

Source: 1972 Census of Manufactures, EPA Project Independence Blueprint, USGPO, November 1974, and ADL estimates.

C. CRITERIA FOR PROCESS SELECTION

In this study we have focused on identifying changes in the primary production processes which have clearly defined pollution consequences. In selecting those to be included in this study, we have considered the needs and limitations of the EPA as discussed more completely in the Industry Priority Report mentioned above. Specifically, energy conservation has been defined broadly to include, in addition to process changes, conservation of energy or energy form (gas, oil, coal) by a process or feedstock change. Natural gas has been considered as having the highest energy form value followed in descending order by oil, electric power, and coal. Thus, a switch from gas to electric power would be considered energy conservation because electric power could be generated from coal, existing in abundant reserves in the United States in comparison to natural gas. Moreover, pollution control methods resulting in energy conservation have been included within the scope of this study. Finally, emphasis has been placed on process changes with near-term rather than long-term potential within the 15-year span of time of this study.

In addition to excluding from consideration better waste heat utilization, "housekeeping," power generation, and fuel switching, as mentioned above, certain options have been excluded to avoid duplicating work being funded under other contracts and to focus this study more strictly on "process changes." Consequently, the following have also <u>not</u> been considered to be within the scope of work:

- Carbon monoxide boilers (however, unique process vent streams yielding recoverable energy could be mentioned);
- Fuel substitution in fired process heaters;
- Mining and milling, agriculture, and animal husbandry;
- Substitution of scrap (such as iron, aluminum, glass, reclaimed textile, and paper) for virgin materials;
- Production of synthetic fuels from coal (low- and high-Btu gas, synthetic crude, synthetic fuel oil, etc.); and
- All aspects of industry-related transportation (such as transportation of raw material).

D. SELECTION OF AMMONIA INDUSTRY PROCESS OPTIONS

Within each industry, the magnitude of energy use was an important criterion in judging where the most significant energy savings might be realized, since reduction in energy use reduces the amount of pollution generated in the energy production step. Guided by this consideration, candidate options for in-depth analysis were identified from the major energy consuming process steps with known or potential environmental problems.

After developing a list of candidate process options, we assessed subjectively

- pollution or environmental consequences of the process change,
- probability or potential for the change, and
- energy conservation consequences of the change.

Even though all of the candidate process options were large energy users, there was wide variation in energy use and estimated pollution loads between options at the top and bottom of the list. A modest process change in a major energy consuming process step could have more dramatic energy consequences than a more technically significant process change in a process step whose energy consumption is rather modest. For the lesser energy-using process steps process options were selected for in-depth analysis only if a high probability for process change and pollution consequences were perceived.

Because of the time and scope limitations for this study, we have not attempted to prepare a comprehensive list of process options or to consider all economic, technological, institutional, legal or other factors affecting implementation of these changes. Instead we have relied on our own background experience, industry contacts, and the guidance of the Project Officer and EPA advisors to choose promising process options.

The manufacture of ammonia is an integrated process, with subprocesses of:

- producing a hydrogen-rich stream from a hydrocarbon or carbon source via reforming or partial oxidation,
- gas purification, and
- ammoniation.

The primary raw material for ammonia in the United States is natural gas, and about 95% of the ammonia manufactured in the United States is so produced.

Within the ammonia industry, our first objective was to identify major energy issues and current and potential environmental problems. We have determined that changes are being considered to increase the efficiency of natural gas processes and to utilize liquid hydrocarbons for a portion of the fuel requirements. Also, because of a shortage of natural gas, several companies are evaluating the option of producing ammonia from coal and liquid hydrocarbons.

We foresee little pollution impact as a result of the changes to improve the conventional natural gas processes, the major one of which is preheating the inlet air.

The major potential change will be seen in the new plants which, because of a shortage of natural gas, may have to use coal or heavy fuel oil both for fuel and for feedstock. Such plants are not commercial in the United States

at present, so they will constitute a major process change. Also, such plants are likely to have pollution problems significantly greater than present plants.

Therefore, we chose to analyze the process options:

- ammonia production based upon coal gasification, and
- ammonia production based upon heavy oil gasification.

The industry description in Chapter III is based on 1974, the last representative year for which there was good statistical information.

For each process, we evaluated capital and operating costs to pinpoint economic factors that would influence the adoption of new technology. Investment costs for the base case and for pollution control costs were also calculated on the same basis.

Recognizing that capital investment and energy costs have escalated rapidly in the past few years and have greatly distorted the traditional basis for making cost comparisons, we believe that the most meaningful economic assessment of new process technology can only be made by using 1975 cost data. Consequently, in estimating operating costs we developed costs representative of the first half of 1975, using constant 1975 dollars for our comparative analysis of new and current processes.

In each case, we estimated capital and operating costs for pollution control systems expected to be capable of meeting existing EPA standards for ambient air quality (SO_2 and particulates) and, for aqueous effluents, the "Best Available Technology." Our estimates were based on the assumption that the pollution control technologies would be adequate in achieving any standards for toxic and hazardous substances, such as trace heavy metals, since there is little or no data available on the probable magnitude of these problems.

II. FINDINGS, CONCLUSIONS AND RECOMMENDATIONS

A. AMMONIA FROM COAL

1. Environmental Aspects

The problems associated with coal gasification are usually gaseous sulfur, non-methane hydrocarbons, wastewaters, ash, and slag. In making ammonia from gasified coal, sulfur must be removed for process reasons and, once removed, it can be handled in an environmentally acceptable manner by the addition of a sulfur recovery system. The hydrocarbons formed in the gasifier are limited to small quantities of methane. The methane, and any traces of higher hydrocarbons which do not take part in the synthesis, are removed from the ammonia loop in a purge stream which is used as supplemental fuel.

The wastewater volume is less in this process than in other coal gasification processes, because the water is recycled to the reactor to provide steam. The components of the ash and slag are similar to those produced in normal industrial coal-fired boilers and are analogous in character, leachability, etc.

There will be no unique problems for commercial ammonia plants based on coal feedstock in meeting the anticipated environmental standards. Difficulties will be no greater than those encountered in electric power generation or in industrial coal-fired boilers.

2. Areas Where EPA Policies May Influence Future Choices of Alternatives

Use of strip-mined coal is attractive for this process alternative, because it provides a lower cost for the feedstock and the stripped area is a potential place in which to dispose of the large quantities of ash and slag. EPA's policy in developing ground rules related to strip mining will influence the trend of the ammonia industry in choosing feedstock and slag disposal methods and, thus, in determining the overall course of the industry.

3. Practices/Processes Requiring Additional Research

In assessing the pollution aspects of the coal alternative, it is apparent that one of the foremost areas requiring research and development efforts is in the measurement and control of volatile materials found in coal, as well as arsenic, boron, fluorine, lead, mercury, and so on. In addition, the control of volatile organic species with known or potential carcinogenic effects may present a problem area for research and development efforts. Research and development into the most environmentally acceptable method for the use or

disposal of the large amounts of solid residues (principally coal ash) should be undertaken to establish procedures and techniques that can be utilized to achieve realistic costs and benefits.

B. AMMONIA FROM HEAVY FUEL OIL

1. Environmental Aspects

As with the coal alternative, the significant potential environmental problem is associated with sulfur. Again, the sulfur must be removed for process reasons by the addition of a sulfur recovery plant and results in byproduct sulfur. The process wastewater is treatable in a conventional biological treatment plant.

Therefore, there will be no unique problems for commercial ammonia plants based on oil feedstock in meeting the anticipated environmental standards.

2. EPA Policies and Requirements for Additional Research

Since the cost for environmental control will not be a significant problem and because the technology is in use, we anticipate little need for policy changes or research on the part of EPA.

TABLE II-1

COMPARISON OF BASE LINE AND ALTERNATIVE PROCESSES

		Natural Gas[1] (Base Case)	Coal Gasification[2]	Heavy Oil Gasification[3]
Environmental	Incremental Pollution Control costs ($/ton of product).	--*	8.65	3.46
	Comments	Costs comparable for ammonia synthesis section of base case and each alternative.	Slag disposal, coal-pile run-off treatment and syngas purification wastewater.	Syngas purification and soot recycle purge wastewaters.
Energy	Consumption (10^6 Btu/ton of product).	37	36	35.4
	Comments	Includes natural gas for feedstock and fuel with small amount of electrical power. (Approximately 1% for pollution control).	Approximately 0.5% increase for pollution control (0.17 x 10^6 Btu/ton).	Approximately 0.4% increase for pollution control (0.13 x 10^6 Btu/ton).
Process Economics	Investment ($ millions)	63.4	101.1	70.6
	Pollution Control and Operating Cost ($/ton of product)**	98.18	146.07	151.14
	Comments	Based on natural gas at $0.85/$10^6$ Btu. (Expected to increase to $2.50 in future).	Based on $15.40/ton of coal ($0.71/10^6 Btu).	Based on $1.90/$10^6$ Btu for high sulfur fuel oil and $2.40 for low sulfur oil.

[1] Details found in Tables IV-3, 4, 5, 8, 10, and 11.

[2] Details found in Tables IV-14, 20, 22, and 24.

[3] Details found in Tables IV-25, 30, and 31.

* Not determined but estimated at < $2.00/ton of product.

** Includes pretax return on investment.

TABLE II-2

AIR, WATER, AND SOLID WASTE STREAMS FROM BASE CASE AND ALTERNATIVE FUEL SYSTEMS AND PROCESS MODIFICATIONS

Process Alternative	Air Emission	Water Effluent Streams	Solid Waste
• Natural gas (base case)	Synthesis loop purge. Product loading emission.	Raw water treatment plant effluent. Cooling tower blowdown. Boiler blowdown. Compressor blowdown. Process condensate.	Shift converter catalyst. Ammonia converter catalyst.
• Coal gasification	Emissions as listed in base case above. Coal handling emissions. Syngas purification emissions. Claus plant tail gas cleanup vent. Byproduct molten sulfur storage & transfer emissions. System vents for pressure let-down.	Effluents as listed in base case above. Coal, ash and slag pile runoff. Wastewater from Rectisol Unit Wastewater from sulfur recovery plant tail gas cleanup.	Solid wastes as listed in base case above. Slag. Catalyst from CO shift. Molten sulfur.
• Heavy oil gasification	Emissions as listed in base case above. Syngas purification emissions Claus plant tail gas clean-up vent. Byproduct molten sulfur storage & transfer emissions System vents for pressure let-down.	Effluents as listed in base case above. Soot recycle system purge. Wastewater from syngas purification. Wastewater from sulf[illegible]covery plant tail gas cleanup.	Solid wastes as listed in base case above. Catalyst from CO shift. Molten sulfur.

III. OVERVIEW OF THE UNITED STATES AMMONIA INDUSTRY

A. DESCRIPTION OF INDUSTRY

1. Introduction

In 1975, some 67 organizations produced anhydrous ammonia in the United States, and operated a total of 94 ammonia plants. The rated design capacity of the industry was approximately 16.9 million tons per year. Several additional ammonia plants are currently under construction. Ammonia production expanded dramatically during the 1960's, almost tripling from 1960 to 1970. Recent production increases have been far more modest, and there has been no significant growth since 1972. (See Table III-1.)

Ammonia is the basic raw material for virtually all nitrogen fertilizers. Furthermore, substantial quantities are also used for the production of non-fertilizer materials, including plastics and resins, synthetic fibers, and explosives.

Ammonia is used directly as a fertilizer and as a raw material for other fertilizer products, including urea, ammonium nitrate, ammonium phosphate, and complete mixed fertilizers. Non-fertilizer uses account for about 20% of U.S. ammonia consumption. A use pattern for ammonia is provided in Table III-2. Ammonium nitrate is used as an explosive in surface mining applications. Urea finds significant uses outside of the fertilizer industry, principally as an animal feed and as a component of thermo-setting resins.

Natural gas is the basic feedstock for virtually all U.S. ammonia production, with minor amounts of ammonia being produced from such byproduct streams as chlorine-cell hydrogen and refinery off-gas. In 1973, ammonia manufacture required 591×10^{12} Btu of natural gas. This represented 3% of the total U.S. natural gas supply. Energy requirements for ammonia manufacture are provided in Table III-3. In view of the critically short natural gas situation, increasing interest is being shown in the use of coal or petroleum as a basic feedstock. However, it is not expected that plants using such feedstocks will be in operation before the early 1980"s.

International trade in nitrogen compounds is significant for the U.S. industry. Because supplies were needed to meet growing domestic requirements, exports have declines from about 1.8 million tons of ammonia equivalent in 1973 to 1.0 million in 1974. Imports have been increasing and now are equal to exports. Because of geographical and individual company considerations, there are generally both imports and exports of anhydrous

TABLE III-1

SYNTHETIC AMMONIA - U.S. PRODUCTION HISTORY
(000 Short Tons)

1960	4,818
1965	8,869
1966	10,605
1967	12,194
1968	12,120
1969	12,769
1970	13,824
1971	14,538
1972	15,193
1973	15,093
1974	15,698
1975 (Est.)	15,680

Source: U.S. Department of Commerce, Current Industrial Reports

TABLE III-2

USES AND SOURCES OF AMMONIA - 1974

	000 Short Tons	%
Fertilizers for Domestic Use	10,800	64
Non-Fertilizer Uses		
Ammonium Nitrate Explosives	550	
Urea - Animal Feeds	350	
- Resins and Other Uses	350	
Nitric Acid (except for Ammonium Nitrate and Fertilizers)	450	
Caprolactam (contained in product only)	40	
Acrylonitrile	410	
Amines	260	
All Other	800	
Subtotal	3,210	19
Exports (Ammonia and Derivatives)	1,020	6
Losses, Inventory Change, & Unaccounted For	1,850	11
Total Uses	16,880	100%
Production - Synthetic	15,700	
- Coke Oven & Other	150	
Imports (Ammonia and Derivatives)	1,030	
Total Supply	16,880	

Source: U.S. Department of Commerce, U.S. Department of Agriculture and ADL Estimates.

TABLE III-3

1973 ENERGY USE FOR AMMONIA MANUFACTURE

	Fuel Use (10^{12} BTU)	Electric Power Use (10^{6} KWH)	Electric Power Use (10^{12} BTU)[1]	Total (10^{12} BTU)
Middle Atlantic	20.3	34.4	0.4	20.7
South Atlantic	36.2	41.7	0.4	36.6
East North Central	36.0	41.5	0.4	36.4
West North Central	83.2	96.7	1.0	84.2
East South Central	62.1	71.5	0.8	62.9
West South Central	280.2	327.3	3.4	283.6
Mountain	14.7	19.7	0.2	14.9
Pacific	42.0	50.4	0.5	42.5
Alaska	17.7	20.4	0.2	17.9
Total	592.4[2]	703.6	7.4	599.8

[1] At 10,500 Btu/kWh.

[2] Of this amount, all but 1.1 (10^{12}) Btu was as natural gas.

Source: Arthur D. Little, Inc.,"Economic Impact of Shortages on the Fertilizer Industry," Report to the Federal Energy Administration, January 1975.

ammonia and its derivatives. Because of the potential limited availability of natural gas for further ammonia plant expansion, the United States may become a major net importer in the not-too-distant future. However, the potential for shifting to coal or petroleum as a feedstock may eliminate the need for such import dependence.

2. Plant Characteristics

A modern ammonia plant is typical of most chemical process units with a realistic useable life of 15 to 20 years or longer. Depreciation is usually on the basis of an 11- to 15-year life.

There are currently 110 ammonia plants in operation in the United States, with 11 under construction or contracted for. Following significant technological developments in the late 1950's, the size of the typical ammonia plant increased substantially to a minimum of 600 tons per day, with most new ones being in the range of 1,000 to 1,200 tons per day. The larger sizes were dictated by the favorable economics of using centrifugal compressors in place of reciprocating ones. However, plants built prior to these developments, with capacities from 50 to 300 tons per day, are still operating. About 53 plants are over ten years old, and represent 41% of total U.S. capacity. (See Table III-4.)

TABLE III-4

AGE OF AMMONIA PLANTS OPERATING
AT BEGINNING OF 1976

Year of First Operation	Number of Plants	Total Capacity 000 tons per year	Total Capacity %
Prior to 1960	27	3,521	19
1960 - 1965	26	3,980	22
1966 - 1970	36	9,941	54
1971 - 1975	4	889	5
	93	18,331	100%

Almost all U.S. ammonia capacity is based on natural gas for feedstock, so the location of a plant depends on access to natural gas. However, because of the nation's widespread pipeline distribution system, ammonia plants are widely scattered. There is a great concentration of ammonia plants along the U.S. Gulf Coast, in Texas, Louisiana, and Mississippi with direct access to natural gas, particularly low-cost intrastate gas. In addition to having low-cost natural gas, this location has low-cost transport to the agricultural heartland in the upper Midwest, by barge shipment up the Mississippi, and more recently through the development of an ammonia pipeline running from the New Orleans area into the eastern and western Midwestern states. The distribution of ammonia plants by region is provided in Table III-5.

TABLE III-5

ANHYDROUS AMMONIA CAPACITY BY REGION IN 1974

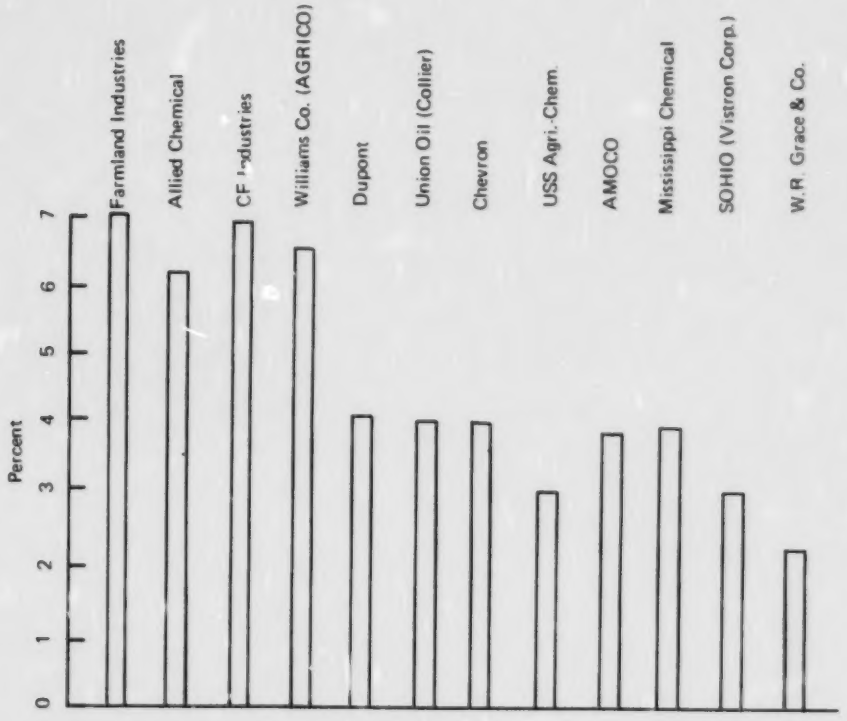
	Number of Plants	Capacity (000 Short Tons Per Year)	(%)
Middle Atlantic	6	859	5
South Atlantic	6	1,042	6
East North Central	4	1,035	6
West North Central	15	2,417	14
East South Central	7	1,786	10
West South Central	31	8,177	47
Mountain	6	493	3
Pacific	12	1,259	7
Alaska	1	510	3
Total	88*	17,578	100%

*Multiple plants at the same site counted as one.

3. Integration and Concentration

Very few ammonia producers sell ammonia strictly in the merchant market. There is a substantial degree of integration to derivatives, both for fertilizer and non-fertilizer purposes. In fact, for many producers, ammonia is produced solely to be used for the manufacture of derivatives or to complement other fertilizer operations.

Ammonia is produced by 67 different companies: 12 companies represent 55% of the total capacity. Major companies and their proportion of the total capacity are provided in Figure III-1.



(1) Based on Production Capacity. 12 Companies Represent 54.9% of the Total Capacity.

FIGURE III-1. MARKET SHARE OF MAJOR U.S. SYNTHETIC AMMONIA PRODUCERS, 1974

B. ECONOMIC OUTLOOK

The rate of growth in the consumption of fertilizer nitrogen in the United States has dropped off significantly over that which prevailed for the years prior to 1970. We have summarized prior consumption data in Table III-6 together with our estimates of the U.S. consumption in 1980 and 1985.

TABLE III-6

FERTILIZER NITROGEN CONSUMPTION

	000 tons N	000 tons NH_3 equivalent
1960	2,738	3,339
1965	4,639	5,657
1970	7,459	9,096
1971	8,134	9,920
1972	8,016	9,776
1973	8,339	10,170
1974	9,157	11,167
1975	8,608	10,498
1980	12,300	15,000
1985 (@ 6%/yr)	16,500	20,122

Growth in consumption for the period of 1960 to 1970 averaged 10.5% per year. This has dropped off significantly following 1970. For the four year period from 1970 to 1974, the average annual growth was 5.3%. The decline in the growth rate in nitrogen consumption in recent years may in part be due to a saturation in the market after many years of very rapid growth. More important contributors, however, were worldwide shortages of nitrogen fertilizer and very significant price increases. In 1975, consumption declined 6% from the previous year. The recent performance of nitrogen fertilizer consumption casts some doubt on future growth rates. However, there is a fundamental need for increasing quantities, and an average growth rate of 6%

per year through 1985 is realistic. Therefore, in Table III-7, we have included our estimates of fertilizer nitrogen consumption in 1980 and 1985, on the basis of a 6% annual growth rate for the next ten years.

TABLE III-7

PROJECTED U.S. NITROGEN SUPPLY/DEMAND BALANCE
thousand short tons of ammonia

	1973/74	1979/80
Uses		
U.S. fertilizer consumption	11,170	15,000
Non-fertilizer uses	3,230	4,570
Losses, inventory change, etc.	1,230	1,950
Exports	1,510	600
Total	17,140	22,120
Sources		
Synthetic ammonia production	15,600	20,240[a]
Other production	240	240
Imports	1,300	1,640[b]
Total	17,140	22,120

[a]Projected, based on plants now in place or under construction and a 90% operating rate.

[b]Needs, based on other projections in the table.

Non-fertilizer uses of ammonia are likewise expected to continue their historic growth rate of about 6% per year, reaching about 4.6 million tons of ammonia equivalent by 1979/80. A projected balance between supply and demand for the United States is provided in Table III-7. In 1973/74, exports exceeded imports by a small margin. The United States has traditionally been a significant exporter, but at the present time imports may be slightly in excess of exports.

While domestic production is expected to expand quite significantly with plants already under construction, those plants will not be able to keep pace with consumption through 1980. If no existing plants are closed down, the United States will produce slightly over 20 million tons of ammonia in 1980, but will need more than 22 million tons, even if exports are cut back drastically. If exports are maintained at the present level, the United States will need more than 23 million tons of ammonia equivalent. This implies that the United States will have to expand either imports or domestic production significantly.

The construction of new ammonia plants is becoming increasingly difficult because of the shortage of natural gas. It is nearly impossible at present to build an ammonia plant based on natural gas in the interstate system. All new ammonia plants under construction are to be based on gas produced within the same state. Even intrastate gas is difficult to obtain, and prices are high. For this reason, producers may begin to consider alternates to natural gas, such as coal and petroleum, as feedstocks for ammonia plants.

The economics of ammonia manufacture are sensitive to the cost of both feedstock and capital investment. Both of these factors have escalated very considerably in the last few years. A plant built in 1968 to produce 1,000 tons a day cost just over $25 million. A similar size plant built today, with only some minor improvements, would cost about $63 million. In the 1960's it was commonplace for ammonia plants to obtain natural gas for about $0.20 per 10^6 Btu: today it is difficult to find gas for less than $1.00 per 10^6 Btu. The difference in the cost of manufacture, including an allowance to provide a return on investment, is provided in Table III-8. Many plants built in the 1960's still enjoy low-cost natural gas under long-term contracts and still have the economics shown, which indicate that ammonia could be sold profitably at less than $45 per short ton. However, if new investment is to be attracted, based on the higher feedstock prices, ammonia prices must be such as to allow for profitable operations, and this price for ammonia must be about $100 per ton. Thus, today there is a significant variation in the profitability of ammonia plants in the United States depending both on when they were built and the current price for natural gas.

TABLE III-8

CHANGE IN THE ECONOMICS OF AMMONIA MANUFACTURE

	Plant Built in mid-60's		Similar Plant Built in 1975	
Year Built	1968		1975	
Capacity - Tons/Stream Day	1,000		1,000	
Annual Production - Tons	340,000		340,000	
Fixed Capital Investment	$25.6 Million		$63.4 Million	
Natural Gas Cost - $/$10^6$ Btu (HHV)	0.20		1.00	
	$/Short Ton	%	$/Short Ton	%
Costs				
Natural Gas 35.8•10^6 Btu/Ton	7.16	17%		
33•10^6 Btu/Ton			33.00	32%
Power & Miscellaneous Supplies	5.17	12	5.17	5
Labor, Maintenance, & Overheads	7.16	17	7.12	7
Subtotal	19.49	46	45.29	44
Investment-Related Costs				
Depreciation 11 years	6.84	16	16.95	17
Local Taxes & Insurance 1.5%	1.13	3	2.80	3
Return on Investment (pretax) 20%	15.06	35	37.29	36
Subtotal	23.03	54	57.04	56
TOTAL	42.52	100%	102.33	100%

IV. COMPARISON OF CURRENT AND ALTERNATIVE PROCESSES

If the natural gas shortage persists, the ammonia industry could be expected to implement the use of alternate feedstocks, such as coal and heavy fuel oil, in 50-100% of new plant construction from 1985 forward, and one or two new plants may be built prior to that time. During this period, 5,000 tons per day of new ammonia capacity will be needed each year. Given this needed rate of new construction, we estimate that 2,500 to 5,000 tons per day of new capacity based on coal or heavy oil feedstocks will be built each year. This corresponds to two to five new plants per year of 1,000 to 1,500 tons per day capacity. New plants as described here, are to provide new capacity rather than to replace existing plants based on natural gas.

To accomplish this for the coal alternative, incremental capital costs of $111 per annual ton of ammonia (a 60% increase) and incremental production costs of $17 per ton of ammonia are anticipated, including $8.65 per ton of ammonia for pollution abatement to satisfy the environmental regulations expected for this alternative process for producing ammonia. In addition, the needed control technology will mean an expenditure of energy equivalent to 165×10^3 Btu per ton of ammonia.

To accomplish this for the heavy oil alternative, capital costs of $21 per annual ton of ammonia (a 24% increase) and incremental production costs of $45 per ton of ammonia are anticipated, including $3.46 per ton of ammonia for pollution abatement to satisfy the environmental regulations expected for this alternative process for producing ammonia. In addition, the needed control technology will mean an expenditure of energy equivalent to 125×10^3 Btu per ton of ammonia.

Nevertheless, these process alternatives appear promising; however, they will require additional research to establish the pollutional character and appropriate control technology to verify the results of this assessment.

A. REASONS FOR CHOOSING OPTIONS FOR IN-DEPTH ANALYSIS

The review of the implications of producing ammonia from coal or oil is necessitated by the real possibility that the processes may be implemented in the United States before 1985, and possibly as early as 1980. The use of coal or oil will be caused by a reduced supply of natural gas, high prices for natural gas, or both.

The United States is faced with a continuing need for increasing its capacity to produce ammonia and is also faced with a rapid decline in the availability of natural gas - the raw material that has been used almost exclusively for the past 30 years. The present and projected scarcity of natural gas has been well documented. The ammonia industry cannot count on

gas as a basis for substantial future growth in this country. Those plants now using gas are faced with stretching their supply by converting heating applications to other fuels and by ensuring they receive proper recognition in the setting of priorities and allocations of available gas supplies.

In addition to the problems concerning the availability of new gas, prices have risen significantly. Until recently, ammonia plants purchased gas at as low as $0.15 per MCF, and few paid more than $0.50. Because a natural-gas-based ammonia plant costs less and is less expensive to operate than either coal- or oil-based plants, ammonia plants have not been designed for operation on coal or oil in areas where natural gas is available. Today, the price of natural gas is much higher, particularly to new customers who are not protected by old contracts. And it is nearly impossible for a new plant to obtain supplies of natural gas from the interstate pipeline system. Thus, new plants must be built using gas produced "in state" which is not subject to federal regulation. Such gas is available - although not readily - and prices range from $0.50 to $2.00 per MCF. Furthermore, contracts written today usually have escalation clauses allowing future price increases.

An ammonia producer wishing to expand is faced with the options:

- Try to find a supply of intrastate natural gas, pay a high price, and assume the risk of further escalation;
- Plan to import ammonia, either by contracting for it or investing in an ammonia plant in a foreign country that has lower-cost gas; or
- Put up an ammonia plant based on coal or petroleum.

These are not easy choices. The federal regulations concerning natural gas may change, thus significantly affecting the price and availability of natural gas in this country. And some new capacity could be based on isolated pockets of natural gas, mine drainage gas, or byproduct gases. However, these represent opportunistic situations rather than a basis for industry expansion.

Foreign investment, when it is made, must be made in countries with surplus gas. By and large, such countries are poor risks for investors, for they generally try to exact a high price for the gas, even though they have little alternative use for it. There would also be high capital and operating costs because of insufficient infrastructure.

On the other hand, before investing in a plant based on oil or coal, one must be confident that raw materials prices are and will continue to be sufficiently lower than those for natural gas to justify the greater investment.

The technology for the partial oxidation of fuel oil is much better established than that for using coal, and also the handling of oil is easier than handling of coal and disposing of ash. However, the supply and price of coal is more secure than for petroleum. On balance, it appears that in the long run, coal will be the preferred raw material while petroleum remains a possibility. Easing of supplies of natural gas would mitigate against either route.

B. COMPARISON OF CURRENT AND ALTERNATIVE PROCESSES

1. Methodology

a. Overview

The base case technology that we use for comparison within this study is production of ammonia based on steam reforming using natural gas as the feedstock. The alternatives as defined in this study are ammonia production based on coal and on heavy fuel oil. In each of the alternatives the feedstock is gasified to produce a synthesis gas (syngas) which is then used to produce ammonia. Because the changes discussed here are all prior to the actual synthesis loop and are related to production of the synthesis gas, we have segmented the discussion of the alternatives as follows:

- Receiving and Storage of Feedstock;
- Gasification (if needed) to produce raw syngas;
- Syngas purification; and
- Ammonia synthesis loop.

As a guide for interpreting the energy and pollution effects of changing feedstocks on the economics of manufacturing ammonia, we have estimated typical investments and operating costs of new plants using natural gas, coal, and heavy fuel oil feedstocks, based on conditions prevailing during March 1975. As the basis for our estimates, we selected the high-pressure reforming centrifugal-compressor type of ammonia plant which has dominated new construction for the past several years (and is expected to continue to do so) and 1,000 tons per stream day for the rated capacity.

Including 90 days of ammonia storage (90,000 tons) we estimated that a natural gas plant would cost $63.4 million, an oil oxidation plant $70.6 million, and a high-pressure coal oxidation plant $101.1 million.

Using high-sulfur Illinois coal (10,800 Btu/lb as mined) charged at $0.71 per thousand Btu, gas at $0.85 per thousand Btu, and oil at $1.90 per thousand Btu, the manufacturing costs are substantially lower for the natural-gas-based plant than for the others because of the sizeable differences in feedstock cost and fixed investment.

To allow for a modest return on fixed capital, an amount equivalent to 20% of the investment was added to the manufacturing cost as shown. It appears that the coal- and oil-based plants are not very competitive under our estimate conditions; assuming, of course, that natural gas is available at 1975 prices.

Within Chapter V we discuss the impact of fuel availability and prices on the cost of producing ammonia and show that - at price ranges different from those prevalent in March 1975 - coal and oil will look attractive as feedstocks.

b. Cost Factors Relevant to Comparing Alternative Processes to the Base Line

The costs of raw materials and byproducts are based on costs prevailing in the first half of 1975.

Energy costs for coal, oil, and natural gas have been based on the existing prices paid in March 1975 by electric utilities. These figures are shown in Table IV-I for the regions considered in our comparisons. We have found that such prices are consistent with prices reported by SIC sector in the 1972 Census. We have escalated such figures by fuel cost indices to 1975. Whereever we have diverged from the March 1975 cost paid by electric utilities we have so indicated. Similarly, energy credits are taken on a consistent basis. It should be recognized that most of the gas and electric utility industry is regulated and, therefore, the price prevalent in the first half of 1975 would not be indicative of what a new plant built on a greenfield site would have to pay. (Estimates indicate that the cost of natural gas for such new facilities might well be equal to that of the price of oil.) Also the price of electric power, to reflect higher fuel costs, might be two or three times higher than electric power costs in early 1975.

The cost of water used purely for cooling purposes was based on $0.03 per thousand gallons. The cost of process water is based on $0.20 per thousand gallons.

We attempted to use the cost of labor wages published by the Bureau of Labor Statistics for March 1975 by industry sector. However, in the ammonia sector, such average labor costs are not generally representative, as shown in Table IV-2. Therefore, we used a higher cost of $6.00 per hour, which better reflects the labor rate. This discrepancy between Bureau of Labor Statistics figures and what we feel to be the current labor rate occurs because of the SIC code grouping used. Agricultural chemicals production, which includes ammonia, involves many industry sections that use relatively low-cost labor. However, ammonia production is a more highly specialized operation.

The costs of maintenance, labor, and materials have been taken as 3% of the initial investment costs for plants based on natural gas, and 3.5 and 4.0%, respectively, for oil- and coal-based plants. This reflects a slightly higher maintenance requirement for such plants. Labor overhead has been taken at 35% of the labor wages. This would account for fringe benefits, such as vacations, holidays, and sick pay, as well as overtime pay.

Miscellaneous variable costs and credits include such items as chemicals, catalysts, supplies, and such services as analytical services.

Under the category of fixed costs we have shown plant overhead at 70% of labor and supervision, which would include items not allocated to the production sector. Local taxes and insurance are taken as 1.5% of the initial capital investment.

To distribute the cost of the capital assets (less salvage value if any) over the estimated life of the facility, annual depreciation is calculated on a straight-line basis over 11 years for the ammonia industry. In addition to being used often in feasibility studies, such a depreciation method and period are consistent with IRS guidelines.

TABLE IV-1

BENCHMARK ENERGY COSTS FOR COAL, OIL, GAS AND ELECTRIC POWER IN MARCH 1975

	Fuel prices[1] ($/10^6 Btu)			$/kWh[2]
	Coal	Oil	Gas	Power
Illinois	0.71	-	0.85	0.019
Middle West	-	2.00	-	
Gulf Coast (Texas)	-	-	0.70	0.014

[1] Average fuel prices paid by steam-electric plants.

[2] 1974 power costs updated to 1975 using factor of 1.17.

Source: Chemical Week, October 22, 1975.

TABLE IV-2

BENCHMARK EMPLOYEE EARNINGS
MARCH 1975

Industry	SIC Code	Hourly Earnings*
Ammonia	287-Agricultural chemicals	$4.43
Fertilizers	287-Agricultural chemicals	4.43
Petroleum Refining	291-Petroleum refining	6.75

* Gross earnings of production or non-supervisory workers.

Source: Employment and Earnings, Vol. 21, No. 11, May 1975, Bureau of Labor Statistics, U.S. Department of Labor.

We have shown an annual allowance for "return on investment" (pre-tax) amounting to 20% of initial capital investment. The allowance is allocated to a ton of product, assuming that the facility operates at 100% capacity.

2. Ammonia Production Based on Natural Gas

Ammonia is used as a source of nitrogen for the production of most fertilizers and is made by the reaction of atmospheric nitrogen with hydrogen. All processes manufacturing ammonia utilize atmospheric air as the source of nitrogen. Hydrogen can be produced from almost any hydrocarbon or carbonaceous material. Careful consideration is given to the choice of raw material, because operating costs for ammonia production are greatly influenced by the cost of producing hydrogen, which in turn is very dependent on raw material cost. Possible sources of hydrogen are natural gas, LPG, naphtha, heavy fuel oil, coal and lignite, electrolytic hydrogen, and by-product hydrogen. As the base case, we selected the high-pressure reforming centrifugal-compressor type of ammonia plant which has dominated new construction for the past several years.

a. Process Description

There are four major operations in manufacturing ammonia: gas preparation, carbon monoxide conversion, gas purification, and ammonia synthesis.

(1) Gas Preparation

Several variations of ammonia synthesis gas processes are available: steam reforming, partial oxidation, the autothermal process, and gasification of coal. The only process of importance in the United States is steam reforming using natural gas as the feedstock, as shown in Figure IV-1.

The primary steam reforming of natural gas is carried out in externally heated tubes containing a reforming catalyst. The feed consists of steam and desulfurized natural gas. A controlled amount of air is added to the primary reformer effluent as it enters the secondary reformer. The secondary reforming is accomplished in a packed catalyst bed in which the heat required for reforming is provided by the partial combustion of the primary reformer effluent. Steam is produced from the flue gas out of the primary reformer and from the process gas leaving the secondary reformer by heat recovery. Plants that have a package boiler typically use it only during startup operations unless steam is needed for the manufacture of derivatives. In the ammonia plant, the steam balance is such that little or no external steam generation is needed during capacity or near-capacity operation.

(2) Carbon Monoxide Conversion

The gas leaving the gas preparation unit is cooled and passed through a converter containing a Mo-Co sulfided catalyst. The carbon monoxide reacts with steam to produce carbon dioxide and hydrogen by the water-gas shift reaction:

$$CO + H_2O \rightarrow CO_2 + H_2$$

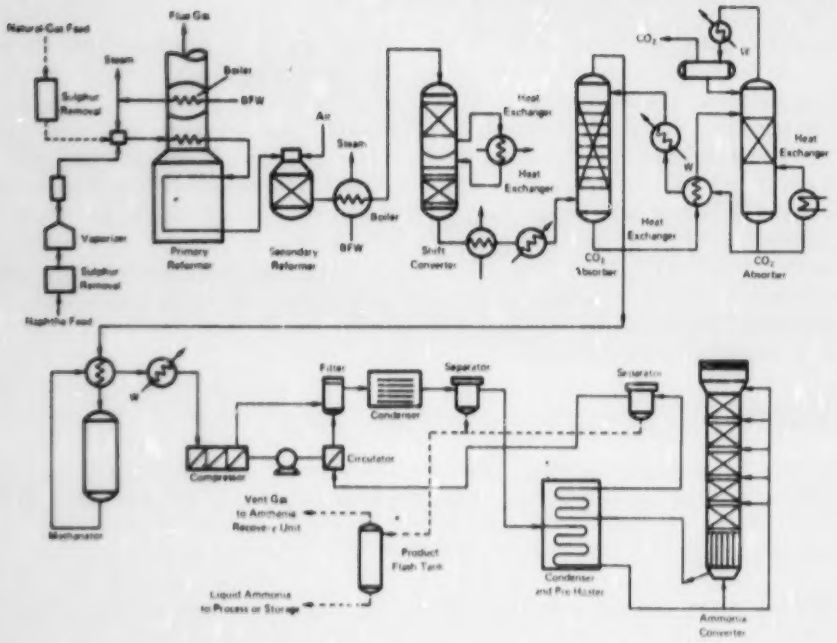


Figure IV-1. Flow Diagram for Synthesizing Ammonia By Steam-Reforming Process

All new processes employ monoethanolamine, hot potassium carbonate, Sulphinol®, or Fluor® solvent to remove the carbon dioxide from the gas stream.

(3) Final Gas Purification

The small amounts of carbon oxides remaining in the synthesis gas must be removed. The three processes that are available are methanation, ammoniacal copper chloride solution absorption, and liquid nitrogen wash.

(4) Ammonia Synthesis

Ammonia is synthesized by the reaction between hydrogen and nitrogen at elevated temperatures and pressures in the presence of a catalyst.

b. Production Cost

Table IV-3 shows typical costs of a large plant (now typical of the U.S. industry). Based on a plant with a capacity of 1000 tons per stream day (which would produce 340,000 tons per year), a Gulf Coast location and March 1975 energy and fuel costs, the estimated cost of producing ammonia would be $127.56 per ton. Of this total cost, $29.38, or 23% represents the cost of the energy inputs. About 14% of the cost is attributable to the feedstock itself, in this case natural gas.

TABLE IV-3

ESTIMATED PRODUCTION COST OF AMMONIA FROM NATURAL GAS (BASE CASE)

Product: Ammonia Process: Steam-methane reforming Location: Gulf Coast

Annual/Design Capacity: 1000 tons/stream day Fixed Investment: $63,400,000

Annual Production: 340,000 tons Stream Days/Yr: 340

	Units Used in Costing or Annual Cost Basis	$/Unit	Units Consumed per Ton of Product	$/Ton of Product
VARIABLE COSTS				
Natural Gas Feedstock	10^6 Btu	0.85	20.4	17.34
Natural Gas Fuel	10^6 Btu	0.85	12.6	10.71
Electric Power	kWh	0.014	95	1.33
Energy Subtotal				29.38
Catalysts & Chemicals				0.60
Cooling Water	1000 gal	0.03	108	3.24
Total				33.22
SEMI-VARIABLE COSTS				
Direct Operating Labor (Wages)	24 men	$12,000/yr		0.85
Direct Supervisory Wages	4 foremen 1 superintendent	$18,000/yr $25,000/yr		0.21 0.07
Maintenance Labor, Materials & Supplies	3% of investment/yr			5.59
Labor Overhead	35% of labor & supervision			0.40
Total				7.12
FIXED COSTS				
Plant Overhead	70% of labor & supervision			0.80
Local Taxes & Insurance	1.5% of investment/yr			2.80
Depreciation	11 yr; straight line			16.95
Total				20.55
TOTAL PRODUCTION COSTS				60.89
Return on Investment (Pretax)	20% of investment/yr			37.29
TOTAL				98.18

c. Energy Usage

Table IV-4 provides a summary of fuel use, by type, for ammonia production. These numbers are based on typical U.S. processes. They do not provide averages for the total industry; rather, they provide the fuel consumption for the most typical process for producing the fertilizer in the United States.

To determine regional use, we estimated production in each of the regions, based on the capacities of production facilities in those regions. Table IV-6 provides a summary of energy use by region and by energy form.

To put the ammonia industry in perspective, the United States consumed approximately $22,600 \times 10^{12}$ Btu of natural gas for all purposes in 1973. The manufacture of ammonia for fertilizers required 490×10^{12} Btu, or about 2.2% of total U.S. natural gas use.

Regional fuel use is in accord with the regional production of the large fuel users. Thus, the West South Central region, which has a very large ammonia capacity, represents some 47% of the fuel used by the ammonia industry. Ammonia plants also are major users of electric power. The most significant electrical energy-using region is the West South Central.

d. Effluent Controls Required for the Base-Case Use of Natural Gas

The manufacture of ammonia from natural gas has associated with it very few environmental problems. Schematic representation of the flowsheet, showing the potential air, water and solid waste emissions, is given in Figure IV-2.

The nature of these emissions is summarized in Table IV-7, and a detailed discussion of each is given in the following sections, including consideration of emission sources and rates, available control technology, and the cost of control. The example calculations given in this section are based on a 1000-ton-per-stream-day ammonia plant using a natural gas feedstock that has negligible sulfur content. The EPA established effluent limitations for the Fertilizer Industry, 40 CFR 418, 8 April 1974. The ammonia industry portion (subpart B) of the guidelines was based on information provided in the Development Document.* Although typical ranges of concentrations are given for cooling towers and boiler blowdown wastewater streams, as well as for process condensate streams, the Development Document for the fertilizer industry presented less quantitative data on wastewater characteristics than is found in the Development Documents for other industries. Consequently, it has been necessary to rely on broad estimates of capital and operating costs for much of the pollution control costs.

*"Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Basic Fertilizer Chemicals Segment of the Fertilizer Manufacturing Point Source Category," U.S. Environmental Protection Agency, March 1974, EPA--440/1-74-011-a.

TABLE IV-4

ENERGY USE IN AMMONIA PRODUCTION

Product or Operation	Energy Factors (units per ton) Electric (kWh)	Natural Gas[1] or Fuel Oil (10^6 Btu)	Steam (10^3 lb)	Total 10^6 Btu Equivalents
Ammonia	45.5	36.5[2]	-	37.0

[1]Table IV-5 describes where the natural gas is used within the process.

[2]Approximately 3.5 million Btu are available from recycle of ammonia synthesis loop purge gas.

Source: Arthur D. Little, Inc., "Economic Impact of Shortages on the Fertilizer Industry," Report to the Federal Energy Administration, January 1975.

TABLE IV-5

NATURAL GAS CONSUMPTION IN AMMONIA PRODUCTION*
(10^6 Btu/ton product)

Feedstock	Reformer Fuel
20.4	12.6**

*Using centrifugal compressors

**Total consumption is 16.1 million Btu. However, 3.5 million Btu per ton are available from tail gas from the synthesis loop.

Source: Arthur D. Little, Inc. estimates.

TABLE IV-6

1973 REGIONAL FUEL AND POWER USE: AMMONIA

	Capacity (000 tpy)		Production Based on Natural Gas (000 TPY)	Natural Gas Used		Fuel Oil Used	Electric Power @ 45.5 kWh[1] 10^6 kWh
	Total	Based on Natural Gas		Feedstock @ 21.9 x 10^6 Btu (10^{12} Btu)	Reformers & Boilers @ 15.6 x 10^6 Btu (10^{12} Btu)		
New England	-	-	-				
Middle Atlantic	859	585	515	12.3	8.0		34.4
South Atlantic	1,042	1,042	917	21.9	14.3		41.7
E.N. Central	1,035	1,035	911	21.8	14.2		41.5
W.N. Central	2,417	2,394	2,106	50.3	32.9		96.7
E.S. Central	1,786	1,786	1,571	37.6	23.2	1.3	71.5
W.S. Central	8,177	8,062	7,093	169.5	110.7		327.3
Mountain	493	423	372	8.9	5.8		19.7
Pacific	1,259	1,208	1,063	25.4	16.6		50.4
Alaska	510	510	449	10.7	7.0		20.4
TOTAL	17,578	17,045	14,997	358.4	232.7	1.3	703.6

[1] Taken on total production--not just natural gas plants.

Source: Arthur D. Little, Inc., "Economic Impact of Shortages on the Fertilizer Industry," Report to the Federal Energy Administration, January 1975.

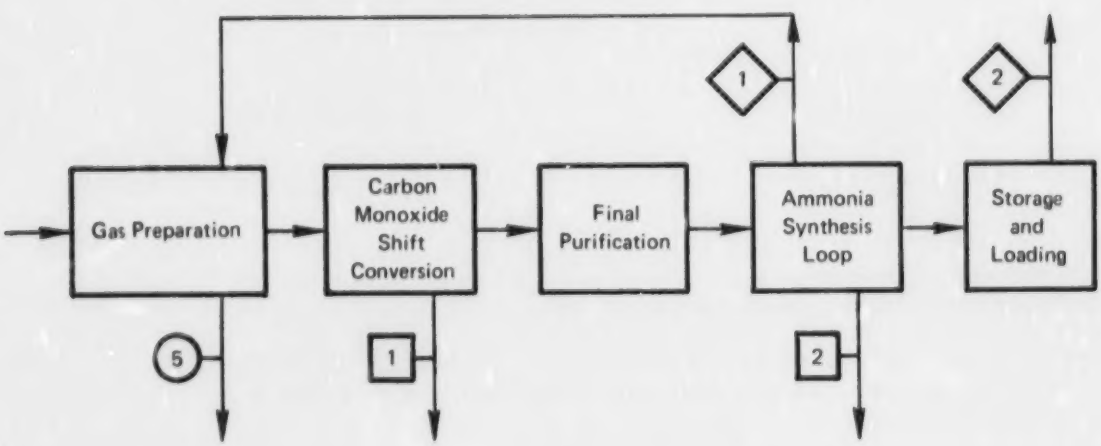


Figure IV-2. Ammonia Production Based on Natural Gas Feedstock

TABLE IV-7

EMISSIONS FROM AMMONIA PLANTS BASED ON NATURAL GAS

		Notes
	WATER EFFLUENTS*	
(1)	Raw water treatment plant effluent	
(2)	Cooling tower blowdown	
(3)	Boiler blowdown	
(4)	Compressor blowdown	
(5)	Process condensate	
	AIR EMISSIONS*	
◇1	Synthesis loop purge	burned as supplemental fuel in reformer
◇2	Product loading emission	
	SOLID WASTES*	
[1]	Shift converter catalyst	recovered
[2]	Ammonia converter catalyst	

*Keyed to Figure IV-2.

(3) Energy Aspects

The best practicable control technologies required to achieve wastewater effluent limitations by 1977 for ammonia production have a high energy component. However, in relation to the total energy requirements for the production of ammonia, the energy requirements for water pollution control are estimated to result in an increase of only 0.9%. These estimates are based on the assumption that the best practicable technology is steam stripping for ammonia. Process steam generated above process requirements can be used for the treatment technology, and thus, it would not increase requirements for scarce fuels such as natural gas in typical plants. Therefore, these environmental requirements should not significantly affect the production of ammonia. However, alternative fuels (i.e., fuel oil) may be utilized to produce the steam required in the effluent control technology in some plants if natural gas is very scarce, thus posing some additional, but minor, problems of control. A summary of the energy aspects are presented in Table IV-8.

(4) Cost Aspects

Current pollution control regulations will have only moderate impact on investment requirements and operating costs in the ammonia industry, as shown in Table IV-9. The energy component of water pollution control costs for the control of nitrogen effluent from ammonia plants is 73% of the total, as shown in Table IV-10. However, these figures are deceiving in that it would be more logical to compare the increased energy requirements to the total energy requirements for the production of ammonia. On such a basis, nitrogen effluent controls would have only a slight impact on the energy requirements for the production of ammonia.

TABLE IV-8

ESTIMATED ENERGY IMPACT FOR AMMONIA PRODUCTION OF CURRENT POLLUTION CONTROL REGULATIONS

Energy Requirements:	Power (kwh)	Fuel (10^6 Btu)	Total[1] (10^6 Btu)
Production (per ton of product)	45.5	36.5[2]	40
Pollution control (per ton of product)	7	0.3	0.37
Percent Increase		0.7	0.9

1. Assumes 10,500 Btu/KWH
2. Approximately 3.5 million Btu are available from recycle of ammonia synthesis loop purge gas.

Source: "Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Basic Fertilizer Chemicals", March 1974.

TABLE IV-9

WATER EFFLUENT TREATMENT COSTS--AMMONIA PLANTS

Treatment Alternative*	1	2	3	4	5
Investment	$302,900	156,650	28,400	152,900	134,300
Return on Investment (pretax)**	60,600	31,350	5,700	30,600	26,900
Depreciation	27,550	14,250	2,600	13,900	12,200
Taxes and Insurance	4,550	2,350	450	2,300	2,000
Operating & Maintenance Costs (excluding energy and power)	12,100	6,300	1,150	33,900	1,750
Energy and Power Costs***	273,600	168,700	7,850	17,200	7,350
Total Annual Costs	$378,400	$222,950	$17,750	$ 97,900	$ 50,200
Energy (10^6 kWh/yr)	12.3	7.5	0.35	0.77	0.33
Raw Waste Load (liters/sec)	17.6	17.6	6.3	27.4	17.3
(gpm)	280	280	100	435	275
Resulting Effluent Level					
(mg/liter)	25 NH_3-N	25 NH_3-N	< 25 oil	5 NH_3-N	10 NH_3-N
(lb/1000 lb)	84 NH_3-N	84 NH_3-N	< 30 oil	5 NH_3-N	33 NH_3-N

1. Ammonia/condensate stripping
2. Integrated ammonia/condensate stripping
3. Oil/grease removal system
4. Biological treatment nitrification-denitrification
5. Ammonia/condensate air stripping

* Treatment Alternatives
** 20 Percent of Investment/Year
*** Energy price basis not given by the source. This number was updated from 1971 using a factor of 1.4.

Size Basis: 90 kkg/day (1000 ton/day) ammonia plant
All cost figures are March 1975.

Source: "Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Basic Fertilizer Chemicals," EPA, March 1974.

TABLE IV-10

WATER POLLUTION CONTROL COSTS[1] ($) AMMONIA/CONDENSATE[2] STEAM STRIPPING

Plant Size	1000 T/D
Investment	$302,900
Return on Investment (pretax) 20%	$ 60,600
Depreciation (11 years, straightline)	$ 27,500
Operating and Maintenance Cost	$ 12,100
Energy and Power Costs	$273,600
Total Annual Costs	$373,800
% of Total Costs for Energy and Power	73%

1. Based on 1971 costs updated by ADL to March 1975.

2. Best practicable technology required July 1, 1977 (water effluent).

3. Energy price basis not given by the source. This number was updated from 1971 using a factor of 1.4.

Source: "Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Basic Fertilizer Chemicals", EPA, March 1974.

(5) Impact of Current Air Related Environmental Problems

The sources, control technology and cost of control of air pollution emissions are described in this section. In compiling the information that is presented, we have relied on information in our own files, industry experts and government information.*

(6) Emissions Sources

We have considered the base case plant as divided into three areas:

Raw Material Receiving and Storage;

Synthesis Gas Production; and

Ammonia Production, Storage, and Loading.

*Air Pollutant Emission Factors, EPA Report No. APTD 0923 (Contract No. EPA 22-69-119) prepared by TRW, Inc., April 1970.

- Raw Materials Receiving and Storage - For a plant manufacturing ammonia from natural gas, receiving and storage is very simple. The gas is usually delivered to the plant via a pipeline and is either used directly or a portion is stored in a pressurized storage tank. There are no air pollutants associated with this operation.

- Synthesis Gas Production - The production of ammonia synthesis gas from a natural gas feedstock is usually accomplished by steam-methane reforming using a nickel catalyst. Since the catalyst is sensitive to sulfur, the feedstock sulfur content is usually kept less than 2 parts per million. Therefore, no significant sulfur emissions are expected in the base case. No particulates are produced in this process. Since the natural gas is often pressurized prior to reforming, the system will be a pressurized one and process leaks are expected to be nil.

- Ammonia Production, Storage and Loading - Most of the potential air pollution emissions associated with ammonia are emitted from the synthesis loop and from product storage and loading. These two sources are briefly described below. There is little difference between this portion of the base case plant and the ammonia production and storage associated with the new technologies discussed in later sections of this report.

- Synthesis Loop Purge - There is a tendency for inert material, such as methane and argon, to concentrate within the synthesis loop. Therefore, there is a purge stream off the ammonia converter exit stream to remove inerts from the ammonia synthesis loop. In early plants, the purge was often vented to the atmosphere and was occasionally scrubbed with water to remove the ammonia, generating a wastewater stream containing ammonia which had to be treated. Currently, the loss of hydrogen from the synthesis loop is not total, because the purge gas can be burned in the reformer furnace. Cryogenic purification of the synthesis gas lowers the inerts in the loop and reduces the purge requirements. In some plants, cryogenic techniques are used to separate methane, argon, and residual ammonia from the purge gas into separate components, each of which can be handled separately without environmental problems. The above processing methods are applicable to both the base case technology and to new technology, so there will not be a net impact changing from one technology to another.

- Product Storage and Loading - Leaks are associated with the handling of ammonia product, with major leaks occurring during transfer of product into trucks or railroad cars. Because the ammonia leaks occur at specific locations within the plant, they can be readily collected and removed by wet scrubbers; however, their collection is usually for occupational safety reasons since the preferred method for removing ammonia from waste streams is via stripping into the air. The control of ammonia leaks from fugitive leaks requires good maintenance, and such leaks rarely occur in quantities great enough to either pose environmental problems or warrant control.

(7) Treatment and Cost of Control

To compare base case technology with new technology, we considered the differences in the environmental control costs to be in the processing areas of Receiving and Storage and Synthesis Gas Production. For the base case technology, the environmental control costs associated with these two processing areas are negligible. There will be a small cost associated with environmental control of the ammonia storage and loading area. An example of the costs that can be expected in controlling storage and loading emissions is shown in Table IV-11. The control of the ammonia emissions is based on a packed column scrubber having a gas flow rate of approximately 2,000 scfm. The scrubber water is treated with the other process wastewaters. The capital cost for the system is approximately $23,500 and the operating costs are approximately $0.03 per ton of ammonia. These costs are considered to be negligible compared to the anticipated environmental control costs associated with the control of sulfur for the new technologies using coal and oil feedstocks. Therefore, they have not been factored into our analysis.

The solid wastes from the process are process catalysts, the sludge from process and wastewater treatment. The catalysts are recovered, with the exception of the iron oxide from the ammonia converter (which is generally landfilled).

TABLE IV-11

EXAMPLE COST OF AMMONIA SCRUBBING[1]

Basis: 2000 acfm	
Capital Investment	$23,500
Operating Cost, $/Year	
Indirect Costs	
Depreciation[2]	2,100
Taxes and Insurance[3]	500
Return on Investment[4]	4,700
Direct Costs	
Electric Power	500
Operating Labor	--[5]
Maintenance Labor and Materials[6]	1,200
Total Annual Cost, $/Year	9,000
Unit Cost, $/ton of ammonia	$ 0.03

[1] March 1975 basis

[2] 11 years, straight line

[3] 2% of investment/year

[4] 20% of investment/year

[5] Negligible

[6] 5% of investment/year

3. Ammonia Production Based on Coal Gasification

a. Process Description

Given the shortage of natural gas, and the need for the United States to reduce its dependence on foreign petroleum, serious consideration should be given to basing future ammonia plants on coal.

A small number of ammonia plants based on coal have been built over the years (Table IV-12), but some of them have since been closed. Nevertheless, recent increases in the price of gaseous and liquid hydrocarbons throughout the world have revived interest in using coal.

Prior to World War II, nearly all synthetic ammonia production was based on the use of coal to produce synthesis gas (a mixture of carbon monoxide and hydrogen) using oxygen (or air) and steam. The coal reaction with the steam is:

$$C + H_2O \longrightarrow CO + H_2$$

Heat must be supplied to support the reaction, in addition to that needed to attain reaction temperature. The heat is supplied by the combustion or partial combustion of coal; the oxygen used burns some of the coal to reach the higher temperatures needed for optimum reaction rates.

There are three categories of gasification:

- Fluidized-bed - Coal is fluidized by oxygen and steam. (The Winkler gasifier is an example.)
- Fixed- (or slowly moving) bed - Coal is supported on a grate. (The Lurgi gasifier is an example.)
- Entrained (or suspended) bed - Coal is suspended in the oxidant gas stream. (The Koppers-Totzek and Texaco gasifiers are examples.)

Using coal as a feedstock from which to obtain a synthesis gas for ammonia production, the objective is to free the hydrogen that is present in the fuel and to react the carbon in the fuel with water vapor to release more hydrogen. The second reaction may proceed directly or after forming an intermediate such as carbon monoxide.

The optimum process would do the reaction simply, with a minimum number of reaction steps and without producing byproducts that have inherent disposal problems. It should also be able to handle a relatively wide range of coal feedstocks, because-even within a given mine-fuel properties vary from sample to sample.

TABLE IV-12

AMMONIA PLANTS BASED ON GASIFICATION OF COAL

Country	Location	Gasification Process	Fuel	Remarks
CSSR	Most (Brüx)	Winkler	Lignite	Initially built for hydrogenation of lignite
Finland	Oulu	Koppers-Totzek	Bituminous coal fuel oil	
France	Mazingarbe	Koppers-Totzek	Bituminous coal	
Germany	Leuna	Winkler	Lignite	In addition to revolving grate and slag-tap gas producers
			Low-temperature coke from lignite	using metallurgical coke
	Wesseling	Pintsch-Hildebrand	Briquettes made of lignite	Initially built for hydrogenation of lignite
		Winkler	Lignite	
		Rummel	Lignite	Molten slag
Greece	Ptolemais	Koppers-Totzek	Lignite	
Spain	Puentes de Garcia Rodriguez	Koppers-Totzek	Lignite	
	Puertollano	Winkler	Bituminous coal	
	Monzon	Wellmann	Anthracite	Revolving grate plus oxygen
Yugoslavia	Goradze	Winkler	Lignite	
Turkey	Kütahya	Winkler	Lignite	
		Koppers-Totzek	Lignite	
Zambia	Kafue near Lusaka	Koppers-Totzek	Bituminous coal	
Pakistan	Daud Khel	Lurgi pressure process	Bituminous coal	
India	Neiveli	Winkler	Lignite	
Thailand	Mae Moh	Koppers-Totzek	Lignite	
Korea (South)	Naju	Lurgi-pressure process	Anthracite	
Japan	Onahama	Koppers-Totzek	Bituminous coal	
	Onahama	VIAG	Bituminous coal	Revolving grate, no oxygen
	Akita	VIAG	Bituminous coal	Revolving grate, no oxygen
	Nagoya	Winkler	Low temperature coke	
	Kurosaki	Winkler	Bituminous coal	
	Toyama	Winkler	Bituminous coal	
		Winkler	Bituminous coal	

Source: Ammonia, Part I, Edited by A.V. Slack and G. Russel James, 1973, Marcell Pekker, Inc., N.Y.

In general, equilibrium favors methane formation at low reaction temperature and high pressure. However, methane cannot be utilized in ammonia production. Hydrogen and carbon monoxide formation is favored at high temperatures.

Winkler, Koppers-Totzek, and Lurgi gasifiers have all been demonstrated in commercial operation and could be deemed proven and reliable. There is a fourth gasifier not yet in full-scale commercial operation which we believe may be very advantageous for ammonia manufacture. A high-pressure partial-oxidation system (such as that developed by Texaco) can produce synthesis gas, without byproducts, at pressures up to 1000 psi. Such a process can use almost any coal, coking or non-coking, high or low sulfur, and can be integrated into an energy-efficient ammonia process.

One such sequence would involve the following steps, which are outlined in Figure IV-3 through IV-8 later in this report:

- Coal receiving and handling,
- Coal grinding,
- High pressure gasification with oxygen,
- Ash removal and handling,
- CO conversion using a sulfided catalyst,
- Heat recovery,
- Acid gas (H_2S and CO_2) removal,
- Low temperature purification,
- Compression, and
- Synthesis and recovery.

Apart from the high pressure gasification step, this integration employs processes that have all been commercially used under the conditions involved and it affords excellent energy efficiency requiring only a modest amount of auxiliary steam for compressors in both air plant and synthesis. A description of the inlet and outlet streams from the gasifier is presented in Table IV-13.

An air separation plant provides oxygen for gasification and high-purity nitrogen for the low-temperature purification section. To remove carbon dioxide and hydrogen sulfide, the Rectisol process may be used, because it provides a separation of the two gases into a pure carbon dioxide suitable for urea production and a hydrogen sulfide-rich stream for conversion to sulfur in a Claus process plant.

TABLE IV-13

GASIFICATION SYSTEM

Basis: Illinois No. 6 Coal
1,000 ton/stream day

	Normal Operation
Gasification System Feed	
Coal (ton/operating day)	1,350
Oxygen (ton/operating day)	1,724
Water (gal/hr)	17,200
Gasification System Product	
Product gas (Hydrogen plus Carbon Monoxide) (10^6 SCF/operating day)[1]	72,700
Slag[2] (ton/day)	181
Utilities Required per MM SCF CO + H_2	
Electrical Energy (kWh)	600
Steam (pounds @ 250 psi)	6,000
Cooling water (gal)	125,000

[1] SCF = Standard cubic feet measured at 60°F and 14.696 psia.

[2] Carbon content, 2% of by wt.

(1) Coal Preparation and Gasification

Ground coal is mixed with a water slurry of recycled soot from the soot thickener. The resulting slurry is pumped to the gasifier, where partial combustion with oxygen takes place under pressure. The synthesis gas (syngas) so produced along with accompanying slag and particulate matter (soot) is quenched by direct contact with water. The slag is removed from the bottom of the gasifier vessel by lock-hopper. The quenched syngas is further scrubbed with hot water to remove the soot, which consists of unconverted carbon and fly-ash. The steam content of the scrubbed gas is sufficient for shift conversion without further steam addition. Condensate return provides the make-up water for the system. It is fed first to the scrubber where it picks up the soot, and then is stripped of dissolved gases, which are principally hydrogen sulfide and carbon dioxide. The acid gases are sent to a Claus sulfur recovery unit. The stripping medium is byproduct nitrogen from the air separation plant.

The stripped soot/water stream goes to a thickener where the soot slurry is concentrated by settling. The clarified overflow water from the thickener is recycled to the gas scrubber. The thickened soot slurry is recycled to the slurry preparation section.

(2) CO Shift Conversion

The product gas from the coal gasifiers, after water scrubbing for removal of ash and soot, contains an appreciable concentration of carbon monoxide. For ammonia synthesis, it is necessary to react the carbon monoxide with hydrogen by use of the CO shift-conversion step, as indicated in the equation

$$CO + H_2O \rightleftarrows CO_2 + H_2$$

This reaction is exothermic and the equilibrium is favored by low temperatures. However, an active catalyst is necessary to get appreciable rates of reaction at low temperatures. About ten years ago, an iron oxide catalyst was the conventional shift-conversion catalyst utilized in many ammonia plants. Because of the relative inactivity of the iron oxide catalyst, the CO conversion had to be carried out at higher temperatures, with a resulting effluent carbon monoxide concentration of 3-4%. Then, a new low-temperature CO shift catalyst was developed using copper and zinc. The catalyst allowed a lower temperature for the CO shift reaction and allowed a more complete conversion of carbon monoxide to hydrogen, so that the effluent carbon monoxide concentration could be less than 1%. The disadvantage of the low-temperature shift catalyst was its extreme sensitivity to sulfur contaminants, so that extra care had to be taken to eliminate all detectable amounts of sulfur from the feed gas to the low temperature shift catalyst bed. A sulfided cobalt-molybdenum catalyst has been developed which is insensitive to sulfur contaminants and allows operation temperatures to be between those of the iron oxide and copper zinc catalysts. With the new catalyst, the residual CO concentration leaving the CO shift converter can be 1-1.5%, with no adverse effects.

Because of the sulfur tolerance of the sulfided cobalt-moly catalyst, and the relatively good conversion of carbon monoxide to hydrogen, the system has been used for the ammonia plant discussed in this report.

The synthesis gas from the gasification step contains sufficient water so that no additional steam is required for the CO conversion step. The feed from the synthesis gas generators is preheated by interchange with the process gas between beds of the CO shift conversion step. Because the CO shift reaction is exothermic and equilibrium is favored by lower temperatures, cooling is desirable between stages of the CO shift converter. For this reason, the reaction is carried out in two or three stages, with intercooling between stages, to achieve the most favorable equilibrium conditions and hence the lowest carbon monoxide content in the effluent gas. Significant quantities of heat can be recovered from the CO shift converter effluent, because it is at about 600°F and contains a fairly large quantity of water vapor. During this heat recovery step, a considerable amount of condensate is produced and is subsequently used as a feed to the gasifier scrubbing and quench system. Any excess condensate from the heat recovery system is stripped of dissolved gases and used as a feed to a boiler feedwater system.

After heat recovery, the effluent from the CO shift conversion step is further cooled to about 110°F before going to the carbon dioxide and hydrogen sulfide removal system.

(3) Acid Gas Removal System

A number of different systems can be considered for the removal of acid gases from the effluent stream coming from the CO shift conversion step. The acid gases that need to be removed are hydrogen sulfide, carbon dioxide and carbonyl sulfide. For efficient operation of the ammonia plant, it is desirable to get the impurities down to only a few ppm. Acid gas removal systems usually utilize either chemical absorption or physical absorption. Of the chemical absorption systems, the amine solvent (monoethanolamine [MEA]) is the most prevalent. One of the problems of using MEA is that is does not efficiently remove carbonyl sulfides. Furthermore, there is no convenient way of selectively separating the carbon dioxide and hydrogen sulfide that are produced when the amine solution is regenerated. Separation of these two acid gases is desirable so that: 1) a higher concentration of hydrogen sulfide can be utilized as feedstock to a Claus sulfur conversion plant; and 2) a high-purity carbon dioxide byproduct stream may be made available as feed material for on-site urea manufacture. Another disadvantage of the amine systems is that they use relatively large amounts of energy for the regeneration step.

Another common acid gas removal system is the hot potassium carbonate system. However, with such a scrubbing system it is difficult to get hydrogen sulfide and carbon dioxide concentrations low enough in the effluent gases to be acceptable for an ammonia plant feed. Furthermore, there is no convenient way of separating the regenerated hydrogen sulfide from the carbon dioxide gas stream.

The physical absorption systems appear to be more amenable to removing acid gases for an ammonia plant utilizing coal gasification as the synthesis gas source. One of the systems that has been used is the Rectisol system, which utilizes cold methanol as the physical absorbent. The Rectisol system has been used to purify synthesis gas produced from coal in South Africa. It has also been used in Germany to remove acid gases in some heavy oil partial oxidation processes in conjunction with ammonia and methanol synthesis. It is an efficient method for removing hydrogen sulfide, carbon dioxide, carbonyl sulfide, water, and other impurities from gas streams.

The Rectisol process is based on the physical absorption of impurities in cold methanol (-20° to -40°F) by countercurrent scrubbing of the process gas in one or two stages. The methanol stream containing the impurities can then be readily generated in a number of stages to produce a high-purity carbon dioxide stream suitable for urea manufacture, or the carbon dioxide stream can be vented to the atmosphere without causing environmental problems. A concentrated hydrogen sulfide stream containing 25-30% hydrogen sulfide can also be produced. This concentration of hydrogen sulfide is quite suitable for efficient conversion to elemental sulfur in a standard Claus conversion plant.

The regeneration of the methanol used for scrubbing requires some inert gas for stripping of the material and also some regeneration by stripping of the methanol by reboiling methanol vapors. The inert gas-stripping material can, in this instance, be readily obtained from the byproduct nitrogen stream produced in the air separation plant associated with producing oxygen for the gasification step.

Because water is also removed from the process gas stream by the Rectisol process, a water-methanol separation step is required. The water that is removed from the methanol solvent is disposed of in a conventional biological wastewater treatment system.

Because the Rectisol process is a low-temperature physical absorption operation, the heats of solution associated with the absorption of the acid gases in the methanol must be removed. A system using ammonia has been considered to satisfy the refrigeration requirement. The tail gas, which is produced primarily from the inert gas stripping of the methanol solvent, will normally have a concentration of less than 1% carbon monoxide and hydrogen, with a maximum of 5 ppm of hydrogen sulfide. This vent stream can normally be vented to the atmosphere.

The Rectisol process normally requires five or six towers to effect the required separation and stripping. By proper use of efficient heat exchangers throughout the system, the energy requirements for carrying out the removal of acid gases from the synthesis gas can be kept to reasonably small quantities.

(4) Final Synthesis Gas Purification and Composition Adjustment

After the hydrogen sulfide and carbon dioxide have been removed from the synthesis gas, contaminants are still present, primarily carbon monoxide, argon and methane. For ammonia synthesis, it is necessary to remove the carbon monoxide impurities down to only a few ppm, because carbon monoxide and carbon dioxide are poisons for the ammonia synthesis catalyst. It is also necessary to add nitrogen to the predominantly hydrogen stream to achieve a 3:1 mole ratio between the materials.

A nitrogen wash system is the most logical method of removing impurities and properly adjusting composition. In the nitrogen wash system, the semi-purified synthesis gas from the acid gas removal system (the Rectisol system) is cooled in heat exchangers and is then contacted with liquid nitrogen. The liquid nitrogen removes the carbon monoxide, methane, and argon impurities and also allows the addition of nitrogen to the required composition. The nitrogen is available at minimum cost from the on-site air separation plant used for supplying the oxygen required for the gasification step.

The low temperature required for the nitrogen scrubbing is produced without the use of a complex refrigeration cycle.

The low temperatures required for the separation process are obtained by mixing the cool nitrogen with the scrubbed gas inside the low-temperature nitrogen wash facility.

In the liquid nitrogen wash system, a residual gas is produced which contains some nitrogen and the impurities that were present in the feed synthesis gas. This gas, with a high enough concentration of combustibles, is often utilized as a supplemental fuel.

The process has no external steam consumption (and no feed water treatment is needed for the steam) because the coal is fed in a water slurry. Thus, gasification steam is internally generated, but of course does require oxygen and coal consumption to supply the heat needed. About 99% of the carbon is gasified.

The gasifier operating pressure of 1200 psi provides a significant savings in total ammonia process compression energy required. Most of the plants listed in Table IV-12 operate at atmospheric pressures, with the maximum pressure below 500 psi. Much less energy is required to compress the oxygen to 1200 psi than to compress the greater volume of synthesis gas to this level. Operation at this pressure level also provides advantages in the synthesis gas purification train.

The very pure synthesis gas from the gas purification train is compressed to 3000-4000 psi for ammonia synthesis. Storage for three months' production is included in the estimates.

The gas is very low in methane, no steam reformer is needed to convert the methane to synthesis gas and, very importantly, the syngas contains no tars, phenols, or other high-molecular-weight byproducts that must be separated in the gas purification train and properly disposed of.

The thermal balance indicates a need for an additional input of 187 million Btu per hour. Assuming a coal-fired boiler with an 80% efficiency (and using 10,870 Btu/lb for the raw coal), about 10 tons of coal/hr are needed to supply the deficit. This is equivalent to 0.24 ton/ton of ammonia.

Cooling water circulation is estimated to be about 3.3 million gal/hr or 80,000 gal/ton of ammonia. Assuming a 5% makeup to the cooling tower, new water needs are 4,000 gal/ton.

Power requirements are estimated to be 162 kWh/ton, including coal grinding but not mining.

Compared to a plant for producing ammonia from natural gas, a coal plant would differ in the following respects. An air separation plant would be required. Oxygen would be used to gasify the coal. Equipment would also have to be added for handling the coal, grinding it finely, and storing it as a slurry for introduction into the reactor. Ash removal and disposal facilities would also have to be included. Essentially all of the ash would be blown down from the quench in the bottom of the reactor. A minor amount would carry over into the soot scrubber and be removed with the soot, which could then be recycled to the partial-oxidation reactor. The amount of carryover would be so small that it would not build up in the recycle stream.

A high-sulfur coal can be utilized and the sulfur recovered in elemental form as a possible byproduct, though probably at low value. Assuming that one of the new sulfide-type shift catalysts is used, the hydrogen sulfide (which is how the sulfur would be generated) is removed and separated from the carbon dioxide by a cold methanol wash. The carbon dioxide can be recovered in a form pure enough for urea manufacture.

b. Cost of Production

Estimates of the capital investment and operating costs were prepared for a "grass roots" plant using a high-pressure coal partial oxidation process, with a capacity of 1000 tons per stream day, located in Southern Illinois where there are considerable deposits of coal near the ammonia market. Investments and operating costs are based on March 1975 cost conditions. The estimated cost of producing ammonia would be $77.95/ton, as shown in Table IV-14. Of this total, $27.26 (35%) represents the cost of energy inputs. About 26% of the total cost is attributable to the feedstock itself, in this case a high sulfur coal. The other power and fuel inputs are needed to supply power in the air separation plant and the ammonia plant and for pump drives.

This process can take advantage of the lower value of high sulfur coals, because as part of the process the hydrogen sulfide form is removed as a potentially marketable sulfur.

c. Energy Usage

The total energy consumption of this process, expressed in Btu equivalents, is 35.83 million Btu/ton of ammonia, as shown below:

		10^6 Btu/Ton
Feedstock	1.33 tons @ 10,870 Btu/lb	28.91
Fuel	0.24 tons @ 10,870 Btu/lb	5.22
Power	162 kWh @ 10,500 Btu/kWh	1.70
Total		35.83

The form of the energy used can vary considerable. We have based our analysis on the probable optimum situation.

d. Effluent Controls Required for Coal Gasification Alternative

The schematic representation of the process considered here is shown in Figures IV-3 through IV-8. The nature of pollutant emissions are summarized in Tables IV-16, IV-17 and IV-18. The major environmental differences between the base case and that of the partial oxidation of coal to supply synthesis gas are:

TABLE IV-14

ESTIMATED PRODUCTION COST OF AMMONIA FROM COAL

Product: Ammonia — Process: High Pressure Partial Oxidation — Location: Southern Illinois

Annual/Design Capacity: 1000 ton/stream day — Fixed Investment: $101,100,000

Annual Production: 340,000 tons — Stream Days/Yr: 340

	Units Used in Costing or Annual Cost Basis	$/Unit	Units Consumed per Ton of Product	$/Ton of Product
VARIABLE COSTS				
Coal Feedstock*	Tons	$15.40	1.33	20.48
Coal Fuel*	Tons	15.40	0.24	3.70
Electric Power	kWh	0.019	162	3.08
Energy Subtotal				27.26
Process Water (Consumption)	1000 gallons	0.20	0.42	0.08
Cooling (Circulating Rate)	1000 gallons	0.03	80	2.40
Catalysts & Chemicals	-	-	-	0.45
Total				30.19
SEMI-VARIABLE COSTS				
Direct Operating Labor (Wages)	32 men	$12,000/yr		1.13
Direct Supervisory Wages	4 foremen 1 superintendent	$18,000/yr $25,000/yr		0.21 0.07
Maintenance Labor, Materials & Supplies	4.5% of investment/yr			13.38
Labor Overhead	35% of labor & supervision			0.49
Total				15.28
FIXED COSTS				
Plant Overhead	70% of labor & supervision			0.99
Local Taxes & Insurance	1.5% of investment/yr			4.46
Depreciation	11 years, straight line			27.03
Total				32.48
TOTAL PRODUCTION COSTS				77.95
Return on Investment (Pretax)	20% of investment/yr			39.47
POLLUTION CONTROL				8.65
TOTAL				146.07

*Coal characteristics presented in Table IV-15

TABLE IV-15

ANALYSIS OF ILLINOIS NO. 6 COAL
(%)

	Raw Coal
As Received Basis	
Moisture	11.76
Ash	11.78
Sulfur	4.34
Btu	10,869
Dry Basis	
Ash	13.35
Volatile	38.60
Fixed Carbon	48.05
Sulfur	4.92
Btu	12,317
MAF Btu	14,215
Ultimate Analysis, Dry Basis	
Carbon	66.95
Hydrogen	4.79
Nitrogen	1.32
Chlorides	0.02
Sulfur	4.92
Oxygen	8.65
Mineral Analysis of Dry Ash	
P_2O_5	0.61
SiO_2	46.49
Fe_2O_3	28.09
Al_2O_3	20.02
TiO_2	0.87
CaO	2.96
MgO	0.71
SO_3	0.10
K_2O	0.01
Na_2O	0.05
Undetermined	0.09

Source: Private communication with Illinois coal company.

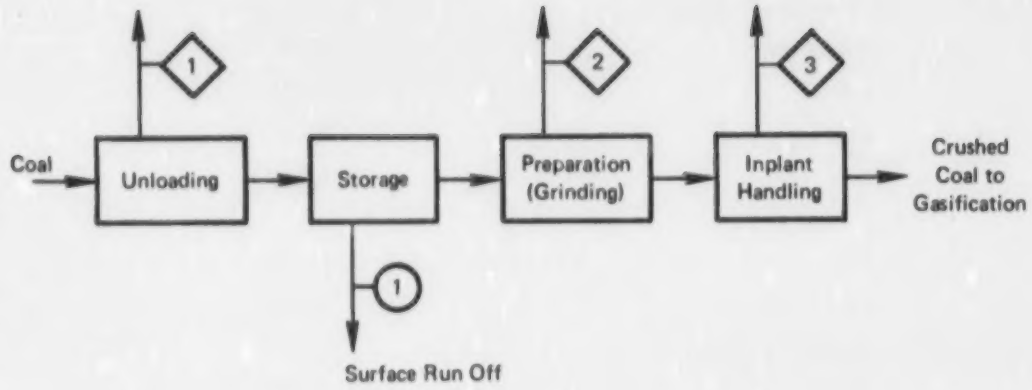


Figure IV-3. Coal Receiving and Preparation

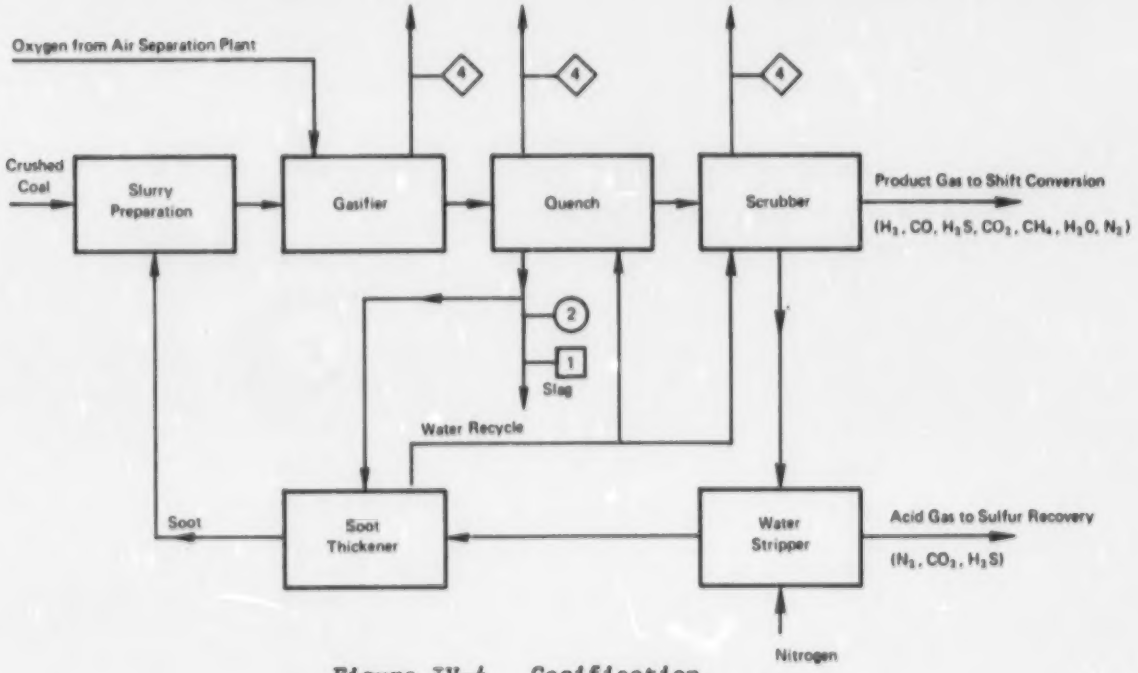


Figure IV-4. Gasification

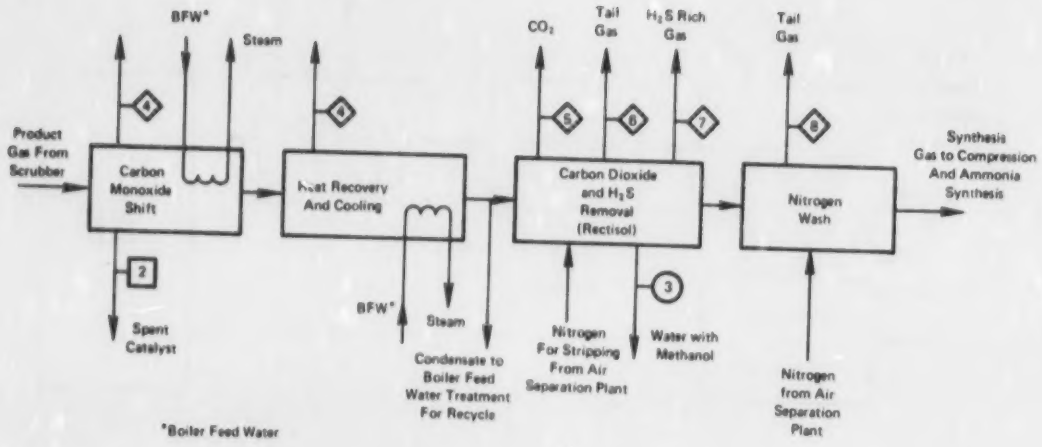


Figure IV-5. Carbon Monoxide Shift and Synthesis Gas Purification

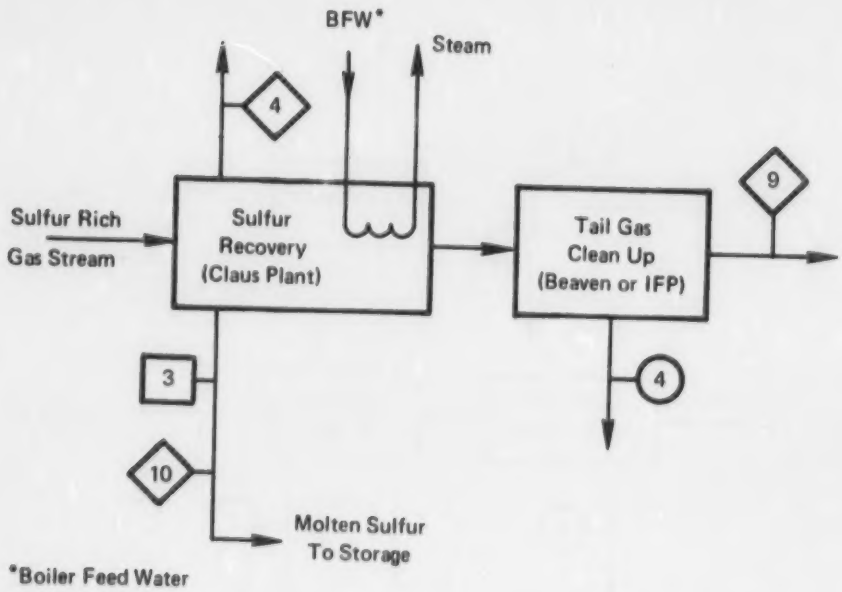


Figure IV-6. Sulfur Recovery

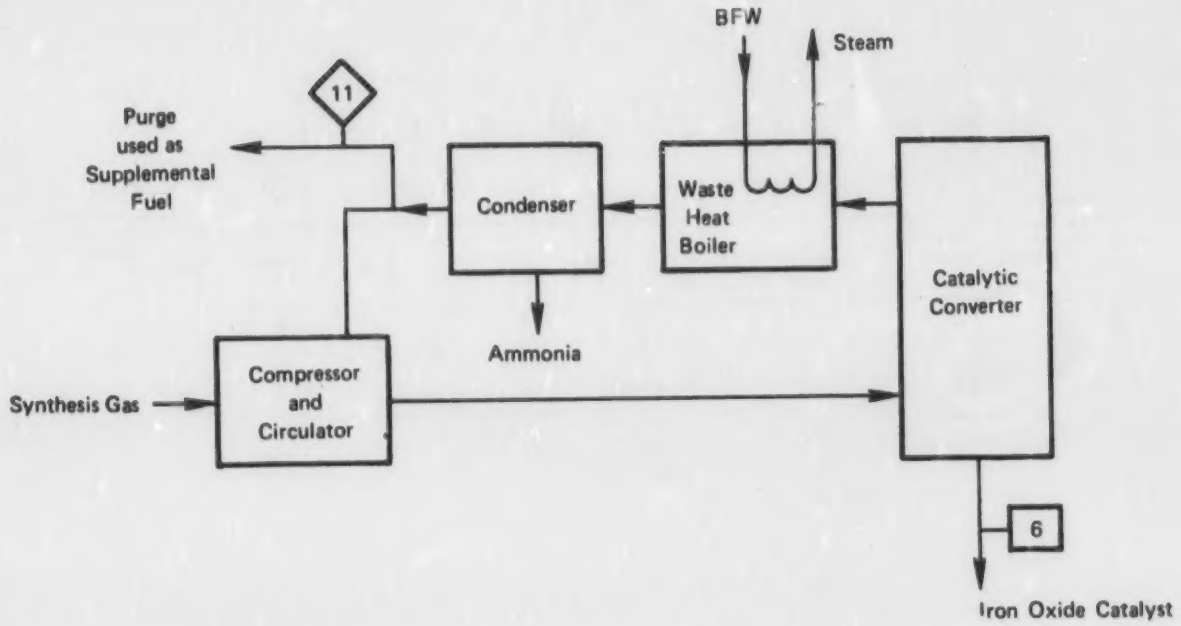


Figure IV-7. Ammonia Synthesis

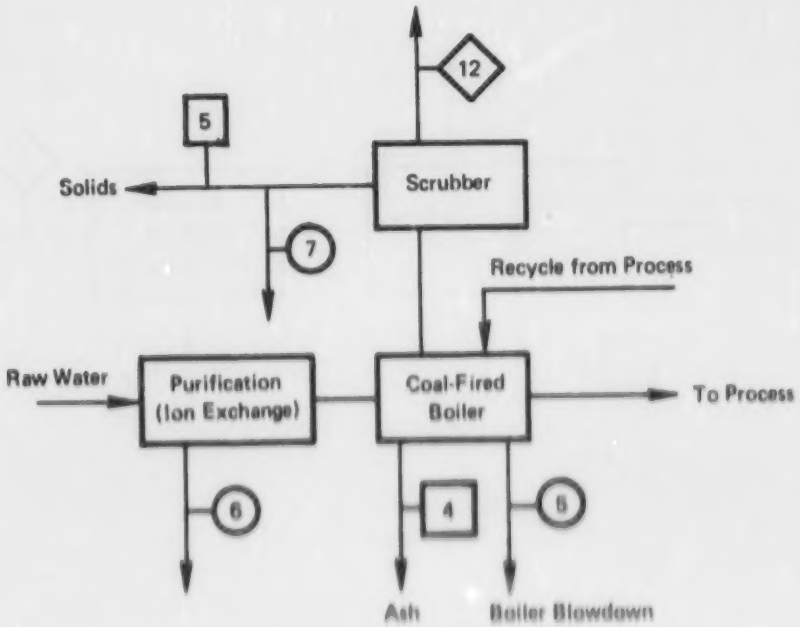


Figure IV-8. Auxiliary Boiler

TABLE IV-16

WATER EFFLUENTS - Ammonia from Coal Alternative	Method of Handling
(1) Coal pile runoff	collected and treated
(2) Ash & slag pile runoff	collected and treated
(3) Wastewater from Rectisol unit	treated
(4) Wastewater from sulfur recovery plant tail-gas cleanup	treated
(5) Boiler blowdown	-
(6) Boiler feedwater purification wastes	-
(7) Coal-fired boiler stack gas scrubber water	-

TABLE IV-17

AIR EMISSIONS - Ammonia from Coal Alternative	Method of Handling
(1) Coal unloading facility emissions	-
(2) Coal grinding	-
(3) Inplant handling of coal	-
(4) System vents for pressure let-down	infrequent; flared
(5) Byproduct CO_2	potential for urea manufacture
(6) Tail gas from Rectisol	vented
(7) Sulfur-rich stream from Rectisol	to sulfur recovery
(8) Tail gas from nitrogen wash	burned in boiler as supplemental fuel
(9) Claus plant tail gas clean-up vent	vented
(10) Byproduct molten sulfur (storage & transfer facilities)	marketed
(11) Synthesis loop purge gas	burned as supplemental fuel
(12) Stack gas from auxiliary coal-fired boiler	scrubbed

TABLE IV-18

	SOLID WASTES - Ammonia from Coal Alternative	Method of Handling
1	Slag	-
2	Catalyst from CO shift	recovered
3	Molten sulfur	marketed
4	Ash from auxiliary coal-fired boiler	-
5	Scrubber water solids from auxiliary coal-fired boiler	-
6	Catalyst from ammonia converter	-

- The use of a coal feedstock introduces the new source of particulate emissions associated with coal-handling;
- Surface runoff from the coal and slag piles must be collected and treated;
- The slag generated must be disposed of in an acceptable manner;
- The use of a coal feedstock will produce a sulfur-laden gas exhaust in synthesis gas purification which must be controlled using, for example, a Claus plant with tail gas cleanup; and
- The sulfur recovery plant will generate additional wastewater that must be treated.

An additional and indirect environmental impact suggested by the change in feedstocks is that an auxiliary boiler used during startup and operation will be based on coal. (For the natural gas reforming process, the startup boiler would be based on natural gas.) The environmental impact of a coal-fired boiler is greater than that of a gas-fired boiler. However, because auxiliary boilers are not an integral part of the manufacturing process, they are not considered in detail under the scope of this study. Discharges would be those common to such boilers in any other facility.

The details (emission rates, control technology, and cost of control) of water and air pollution, solid waste disposal, and other environmental concerns are discussed in the following sections of this report. For comparison, the environmental impact of the base case, use of natural gas in steam-methane reforming, is considered to be negligible.

(1) Slag Pile Runoff

Slag removed from the gasification unit would present a disposal problem. If the ammonia plant is not located within close proximity of the coal mine (where the ash can possibly be returned) it must be held on-site in slag piles.

As in the case of the coal storage pile runoff, the slag pile may present a water pollution problem. As shown in Table IV-19, both ash and slag contain a variety of heavy metals, many of which are leachable in water. The runoff would also contain large quantities of suspended solids resulting from fine ash particles being carried away with the water. Again, the composition of the runoff is very difficult to predict.

Slag would be generated at a rate of 62,000 tons per year. A storage area capable of containing a 15-year accumulation would occupy an area of approximately 26.5 acres. A yearly rainfall rate of 33 inches per year would result in an estimated average runoff flowrate of 81,000 gallons per day (including 25% additional capacity), and the treatment system would require appropriate retention basins.

(2) Cooling Tower Blowdown

The coal-gasification-based ammonia plant has a cooling water circulation rate of 80 million gpd. Typically, cooling water is recirculated in a tight recycle loop. Based on a cooling water blowdown rate of 1%, the cooling tower blowdown flowrate is 800,000 gpd. Due to the concentrating effect of the whole cooling circuit, inorganic salts present in the water supply would be greatly concentrated. Also, and more important from a pollutional point of view, there would be the presence of cooling water corrosion inhibitors. In particular, if chromate corrosion inhibitors are used, the cooling tower blowdown would have to be treated prior to discharge.

e. Environmental Effects Related to Water Pollution

The coal gasification alternative generates the following wastewater streams (excluding mining):

- Coal pile runoff,
- Slag and ash pile runoff,
- Cooling tower blowdown, and
- Wastewater from the synthesis gas purification system.

TABLE IV-19

ELEMENTAL DISTRIBUTION IN COAL, SLAG, AND FLY ASH

	Element concentration, ppm		
	Coal	Slag	Outlet Fly Ash
Al	10,440	102,300	76,000
As	4.45	18	440
Ba	65	500	750
Br	3.7	2	
Ca	4,340	46,000	32,000
Cd	0.47	1.1	51
Ce	8.2	84	120
Cl	914	<100	
Co	2.9	20.8	65
Cr	18	152	900
Cs	1.1	7.7	27
Cu	8.3	20	
Eu	0.1	1.1	1.3
Fe	10,850	112,000	150,000
Ga	4.5	5	
Hf	0.4	4.6	5.0
Hg	0.122	0.028	
K	1,540	15,800	24,000
La	3.8	42	42
Mg	1,210	12,400	
Mn	33.8	295	430
Na	696	5,000	11,300
Ni	16	85	
Pb	4.9	6.2	650
Rb	15.5	102	190
Sb	0.5	0.64	55
Sc	2.2	20.8	36
Se	2.2	.080	88
Si	23,100	229,000	
Sm	1.0	8.2	9
Sr	23	170	
Ta	0.11	0.95	1.8
Th	2.1	15	26
Ti	506	4,100	10,000
U	2.18	14.9	
V	28.5	260	1,180
Zn	46	100	5,900

Source: Klein, D.H. et al, "Pathways of Thirty-seven Trace Elements Through Coal-Fired Power Plants", Environ. Sci. & Tech., 9: 10, pp 973-978, 1975

(1) Coal Pile Runoff

In the coal gasification alternative, approximately 122,000 tons of coal (a three month supply) are stockpiled on site. Rainwater runoff from the coal pile would contain coal particulates, organic and inorganic compounds leached out of the coal by the rainwater, and oxidation reaction products.* The exact composition of the coal pile runoff is difficult to predict, as it is heavily dependent on the type of coal, rainfall occurence, and type of storage. However, there are a variety of heavy metals and sulfur compounds present in coal. Bacterial action taking place within the wet coal pile very likely would oxidize some of the sulfur compounds into sulfates, thus causing the runoff water to be slight acidic, not unlike acidic mine drainage. The presence of leached heavy metals and acidity in the runoff water would require that the runoff water be collected and treated prior to discharge.

Based on a coal pile occupying 6.3 acres, and an average yearly rainfall of 33 inches per year, the estimated average daily flow of coal pile runoff water would be approximately 19,000 gpd (including 25% additional capacity).

The system for treating runoff water is based on using a retention lagoon to contain the high flow rates that would result from heavy rains and pumping from the lagoon through the wastewater treatment plant at a lower average rate. In this way, capital investment cost for the wastewater treatment would be lowered.

(2) Synthesis Gas Purification System Wastewater

The carbon dioxide and hydrogen sulfide removal system (Rectisol) and the sulfur recovery plant tail gas cleanup system produce wastewater streams that must be treated.

The Rectisol unit will generate a wastewater stream containing an estimated 2% concentration of methanol.

The sulfur-recovery tail gas cleanup unit will generate a wastewater stream containing hydrogen sulfide (at approximately 50 mg/l concentration), carbon dioxide, and possibly small quantities of organic material.

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*"Potential Pollutants from Fossil Fuel Conversion Processes" by the Exxon Government Research Laboratory, EPA Contract No. 68-02-0629.

An estimate of the volume and composition of these streams is:

	Wastewater from CO_2 and H_2S Removal System	Wastewater from Sulfur Recovery Plant Tail Gas Cleanup	Total
Flowrate (gpd)	10,000	8,000	18,000
Methanol (lb/day)	1,680	-	1,680
Hydrogen sulfide (lb/day)	-	3.4	3.4
Estimated BOD_5 (lb/day) (including misc. organics)	1,350	650	2,000

(3) Other Ammonia Production System Wastewaters

There are a number of wastewater streams from the ammonia production unit (described earlier in this report under the base case technology), including process water treatment plant effluent, boiler blowdown, and process condensate. Because the same ammonia production units are used for each of the process alternatives, there will be no significant difference in either wastewater flowrate or composition. Thus, comparing effluent loadings and wastewater treatment costs, the ammonia production unit essentially cancels out. In the comparisons that follow, effluent loadings and wastewater treatment costs are incremental to those of the base case -- natural gas as feedstock for ammonia production.

(4) Miscellaneous Wastewater Streams

In addition to the above, the coal gasification alternative will produce from an auxiliary coal-fired boiler a boiler blowdown stream, an ion-exchange spent-regenerant brine stream and a stack gas scrubber water stream. Study of these streams is outside the scope of this study. As noted earlier, these wastes are those generated by such a boiler system at any facility.

f. Wastewater Treatment Technology

(1) Runoff and Cooling Tower Blowdown Treatment

The coal pile runoff contains acid, soluble heavy metals and organics; the slag pile contains heavy metals; and the cooling tower blowdown may contain chromium. Because all three of the wastewaters can be treated with lime to both neutralize the acidity and precipitate the heavy metals, they can be combined in a single wastewater stream with a 900,000 gpd flowrate.

A conceptual process configuration of the coal storage and slag pile runoff collection system would consist of,

- An earthen dike around the perimeter of the storage areas;
- Collection pumps with pumping equipment;
- Piping;
- A retention basin capable of containing the short-term runoff from a severe storm; and
- A pumping system capable of feeding water from the retention basin to the treatment plant at a controlled rate.

The coal storage area and the slag disposal area each would have their own runoff collection system. The total runoff water would be combined with the cooling tower blowdown stream and then sent to the wastewater treatment plant. The wastewater treatment plant would consist of:

- A 24-hour equalization basin,
- A solids recirculation clarifier, and
- A chemical feed system.

The chemical feed system would consist of a sulfur dioxide feeder (for the reduction of hexavalent chromium to trivalent chromium) and a lime feeder. The precipitated metals would be removed as a sludge from the clarifier.

The wastewater treatment system would have the following estimated chemical and energy consumption:

Hydrated lime - 255 ton/yr
Sulfur dioxide - 75 ton/yr
Electricity - 342,120 kWh/yr

and would generate an estimated 17,800 tons per year of wet sludge containing 10 percent solids.

(2) Synthesis Gas Purification Wastewater Treatment

Wastewaters from the units contain biodegradable material (methanol is highly biodegradable, while hydrogen sulfide is somewhat biodegradable in low concentrations), and as such can be treated in a conventional biological treatment system. A biological treatment system capable of treating this wastewater is envisioned to consist of the following:

- A 24-hour equalization basin;
- A 15-day aerated lagoon;
- A 15-day non-aerated lagoon; and
- A nutrient feed system.

Ammonia and phosphoric acid would have to be fed to the wastewater system to supply nutrients to the microorganisms. Excess microorganisms accumulating in the non-aerated basin would be periodically removed as a sludge.

The wastewater treatment system would have the following estimated chemical and energy consumption:

Ammonia	-	2.05 ton/yr
Phosphoric acid	-	1.1 ton/yr
Electricity	-	304,400 kWh/yr

and would produce 365 tons per year of wet sludge.

With proper operation, the wastewater treatment facility should be able to effect a 90% BOD_5 removal, because no unusual biotoxicants are believed to be present, in which case the effluent BOD_5 loading is estimated to be 200 pounds per day.

g. Wastewater Treatment Cost

Estimated wastewater treatment costs are presented in Table IV-21. As can be seen from Table IV-20, 95% of the wastewater treatment cost is associated with runoff treatment. The capital investment for this portion of the treatment breaks down as follows:

Coal storage diking and collection system	$1,358,000
Slag pile diking and collection system	2,789,000
Wastewater treatment plant	582,000
Total	$4,429,000

Thus over 60% of the total treatment cost is associated with controlling runoff from the disposal of slag. If specific conditions permit the slag to be disposed of without a runoff collection and treatment system, the estimated cost of wastewater treatment would be lowered considerably.

TABLE IV-20

COAL GASIFICATION ALTERNATIVE-
WASTEWATER TREATMENT COST ESTIMATES
(BASIS: 1000 TPD AMMONIA PRODUCTION)

	Treatment of Wastewater from Runoff	Treatment of Wastewater from Synthesis Gas Purification System	Total Wastewater Treatment Cost
CAPITAL INVESTMENT	$4,429,000	$200,000	$4,629,000
INDIRECT COSTS			
Depreciation (@9.1%)	403,000	18,200	421,200
Return on Investment (@20%)	886,000	40,000	926,000
Taxes and Insurance (@2%)	89,000	4,000	93,000
TOTAL INDIRECT COST	$1,378,000	$ 62,200	$1,440,200
DIRECT OPERATING COST			
Operating Labor (plus OHD)	66,300	16,500	82,800
Maintenance (Labor & Supplies)	67,600	8,000	75,600
Chemicals	40,500	900	41,400
Electric Power (@ $0.02/kwh)	8,000	6,100	14,100
Sludge Disposal (@ $5.00/ton)	89,000	1,800	90,800
TOTAL DIRECT OPERATING COST	$ 271,400	$ 33,300	$ 304,700
TOTAL ANNUAL COST	$1,649,400	$ 95,500	$1,744,900
UNIT COST ($/ton of ammonia)	$4.85	$0.28	$5.13

SOURCE: ADL Estimates

h. Environmental Effects Related to Air Pollution

The switch to partial oxidation using a coal feedstock, rather than steam reforming using natural gas, is expected to have the following impacts on air pollution control (excluding mining and transportation):

- Coal receiving and storage - the use of coal as a feedstock will require facilities for unloading and storage, coal grinding, and conveying to the process, all of which generate particulate emissions;

- Synthesis gas production - the use of coal as a feedstock introduces significant sulfur which is removed from the synthesis gas and which is then removed from exhausts venting to the atmosphere;

- Ammonia production, storage, and loading - the emissions from the ammonia manufacturing operations are the same for the partial oxidation process as those described earlier in this report under the base case technology. There is no significant difference in the environmental impact of the two cases.

A comparison of the emission factors for each feedstock is given in Table IV-21. The switch to a coal feedstock introduces a new pollutant emission in most cases, as opposed to an increase or reduction in an existing pollutant. The ammonia synthesis loop, storage and loading are considered to be equivalent for technologies based on natural gas or coal. While the sources must be controlled using, for example, scrubbers on ammonia leaks from storage and loading, flares or afterburners for intermittent plant residue gas, and so on, there is no evidence to suggest that these sources are significantly larger or smaller than comparable sources in plants using natural gas feedstock and, for this reason, these sources are not considered in detail here. Additional information is provided under the base case.

(1) Receiving and Storage

One of the common air pollution problems associated with the use of coal is its tendency to form a fine dust. Operations within a plant specifically causing this problem are:

- Unloading of railroad cars,
- Coal storage,
- Coal grinding, and
- Coal conveying.

TABLE IV-21

SUMMARY OF AIR POLLUTION EMISSION FACTORS

Source	Pollutant	Emission Rate (lb/ton) Natural Gas	Coal	Control Technology
Receiving and Storage				
- Coal Unloading	particulate	-	unk.	Fabric Filter
- Coal Storage	fugitive particulate	-	unk.	-
- Coal Grinding	particulate	-	unk.	Fabric Filter
- Material Handling	particulate	-	unk.	Fabric Filter
Synthesis Gas Production				
- Tail Gas	H_2S	-	<0.2	Sulfur recovery plant with tail gas cleanup
- Pressure Let Down	CO, H_2S	-	unk.	Flare
Ammonia Production, Storage, Loading				
- Purge Gas	NH_3	3	3	Wet scrubber or use as fuel
	CH_4	90	90	
- Storage and Loading	NH_3	2	2	Wet scrubber

In the case of car dumping and coal grinding, the source is at a single point in the plant where it can be controlled using an appropriate hood and fabric filter. The capital costs for such systems are not related to the size of the plant, but rather to the size of a typical railroad car itself. The estimated capital and annualized operating costs for the two control requirements are shown in Table IV-22.

The control of dusting associated with the coal storage piles is much more difficult, because coal piles can spread over as much as six acres, making hooding or collection of particular emissions virtually impossible. In this case, the industry has resorted to the use of sprays to wet down the surface coal piles to minimize dusting. The costs of such systems are only a minor part of the equipment found within a coal yard and are generally included as a part of the coal handling apparatus.

Dust emission during conveying of coal to different parts of the plant is also a fugitive emission source which is not confined to a single spot in the plant and is therefore difficult to collect. In most cases, the control of such emissions is limited to the use of covered conveying belts to minimize dust losses. The cost of such a system would depend also entirely on the length of the conveyor and the corresponding cost for fabrication and erection of the ducting required to collect the emissions. At the present time, control of this type of fugitive emission is not required, and we have not included the costs of such controls in our estimate of the environmental costs for the ammonia industry.

(2) Synthesis Gas Production

The major emission associated with the production of synthesis is the highly concentrated, sulfur-laden exhaust from the acid gas removal system. An approximate sulfur balance for the synthesis gas production is shown in Table IV-23. The amount of sulfur in the acid gas exhaust is about 60 long tons/day, which is large enough to require sulfur control using, for example, a Claus process. Because several states have emission standards regulating the tailgas from sulfur recovery plants, we have assumed that tail gas cleanup will also be required. The combination is expected to reduce the plant sulfur emissions to about 150 ppm.

The cost of sulfur recovery plant plus tail gas cleanup is shown in Figure IV-9. These costs, which appear to be high, are based on information obtained by EPA.* The operating costs for such a plant are shown in Table IV-24. With sulfur credited at $25/long ton, the cost for control is $2.97/ton of ammonia.

*Standard Support and Environmental Impact Document, April 1975.

TABLE IV-22

CAPITAL AND OPERATING COSTS FOR COAL HANDLING PARTICULATE CONTROL

Coal Gasification Alternative
(534,000 ton/yr of coal)

CAPITAL COSTS	$460,000
ANNUAL OPERATING COST, $/Yr	
Indirect Operating Costs	
- Depreciation	41,800
- Return on Investment (@ 20%)	92,000
- Insurances and Taxes (@ 2%)	9,200
TOTAL INDIRECT COSTS	$143,000
Direct Operating Costs	
- Labor	
Direct (@ 450 Man-Hours/Yr, $6.00/hr	2,700
Supervision (@ 15% of Direct)	400
Labor Overhead (@ 35% of Direct and Supervision)	1,100
Plant Overhead (@ 70% of Direct and Supervision)	2,200
- Maintenance (@ 5% of Capital)	23,000
Electric Power (@ $0.02/Kwh, 240,000 Kwh/Yr)	4,800
Fabric Replacement	8,000
TOTAL DIRECT COSTS	$42,200
TOTAL ANNUAL COST, $/Yr	$185,200
UNIT COST, $/Ton of Ammonia	$0.54

SOURCE: ADL Estimates

TABLE IV-23

APPROXIMATE SULFUR BALANCE, TPD
(BASIS: 1000 TPD AMMONIA)

Plant Stream	Total Weight TPD	Sulfur Load	Sulfur Weight TPD
Coal Feed	1350	4.92%	66.4
Acid Gas Removal Exhaust (to Sulfur Recovery)	187	35.5	(66.4)
Sulfur Recovery Plant Exhaust			
- Claus Plant Exhaust	-	2000 ppm	(3.3)
- Tailgas Cleanup Exhaust (to Flare)	-	150 ppm	<0.1
Molten Sulfur Product	66.3	100%	66.3

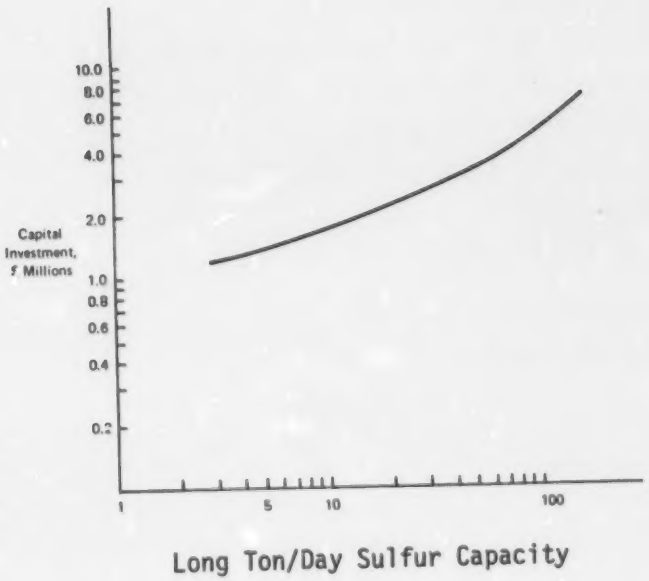

Figure IV-9. Capital Investment -- Claus Plant (Including Tail Gas Cleanup)
SOURCE: Arthur D. Little, Inc., estimates

TABLE IV-24

SULFUR CONTROL COSTS FOR ACID GAS EXHAUST

Coal Gasification Alternative

(BASIS: 1000 TPD of Ammonia, 60 LT/D of Sulfur)

CAPITAL COSTS, ($1,000's)	$3,600
ANNUAL OPERATING COST, $1,000's/Yr	
Indirect Operating Costs	
- Depreciation, 11 years	$327
- Return on Investment (@ 20%)	720
- Insurance and Taxes (@ 2%)	72
TOTAL INDIRECT COSTS	$1,119
Direct Operating Costs	
- Labor	
Direct (@ $6.00/Hr, 1 Man/Shift)	50
Supervision (@ 15% of Direct Labor)	7
Labor Overhead (@ 35% of Direct and Supervision)	20
Plant Overhead (@ 70% of Direct and Supervision)	39
- Maintenance (@ 5 %)	180
- Utilities	
Electric Power (@ 140 kWh/LT, $0.02/kWh)	57
Fuel (@ 0.8 x 10^6 Btu/LT, $2.00/$10^6$ Btu)	33
Cooling Water (@ 20,000 gal/LT, $0.03/$10^3$ gal)	12
- Chemicals (@ $2.50/LT in tailgas)	3
TOTAL DIRECT COSTS	$401
Byproduct Sulfur Credit (@ $25/LT , 60 LT/D)	(510)
TOTAL ANNUAL COST, $1,000's/Yr	$1,010
UNIT COST, $/Ton NH_3	$2.97

SOURCE: ADL Estimates

(3) Ammonia Production, Storage and Loading

The environmental problems associated with ammonia production, storage, and loading are described earlier under the base-case techology. The problems associated with partial oxidation are identical and the costs will be the same. We have not included here a quantitative estimate of the pollutant loads or environmental costs, because they do not result in a net change between the two technologies. However, to place the costs in perspective, we would estimate that the costs for the miscellaneous scrubbers or flares necessary to control a typical 1,000 ton/day ammonia plant would amount to less than 5% of the control costs for other air pollution emission sources.

i. Environmental Effects Related to Solid Waste Disposal

As discussed previously, the major solid waste stream is slag. Added to this are smaller quantities of sludges from the wastewater treatment plant. The total annual quantities of solid waste are:

Slag	- 62,000 ton/yr
Runoff treatment plant sludge	- 17,800 ton/yr
Synthesis gas purification wastewater plant sludge	- 365 ton/yr

The cost for disposal of these wastes is included as part of the wastewater control costs. In addition the catalysts occasionally replaced are:

CO shift conversion catalyst	- recovered
Acid gas removal system catalyst	- recovered
Ammonia converter catalyst (iron oxid	- not recovered

4. Production of Ammonia from Heavy Fuel Oil

a. Process Description

In the early 1950's, industrial processes were developed for producing a synthesis gas, carbon monoxide and hydrogen by the partial oxidation of hydrocarbons, a process which is applicable to materials ranging from methane to heavy petroleum residuals. The basic concept consists of reacting the hydrocarbon with oxygen in the presence of steam at a temperature of 2000° - 2500°F. The following reactions take place:

$$C_nH_m + (m/2)O_2 = nCO + (m/2)H_2$$

$$C_nH_m + nH_2O = nCO + (n + m/2)H_2$$

Carbon dioxide is also formed and the entire reaction mixture is essentially at thermodynamic equilibrium at the temperature involved. Minor amounts of methane are present in the product gas, corresponding to equilibrium conditions, and - depending on the composition of the hydrocarbons - some amounts of hydrogen sulfide, carbonyl sulfide, and ammonia will be present.

In carrying out the reaction, the ratio of oxygen to hydrocarbon is optimized to achieve the desired temperature under adiabatic conditions which will give maximum conversion to CO and H_2. These conditions usually result in 1-3% of the carbon in the hydrocarbon being converted to solid carbon (soot) in the reaction.

The hot gas from the reactor is rapidly quenched to 350°-400°F to "freeze" the composition and to cool it for further processing. The suspended carbon is then removed and the crude synthesis gas is processed in a manner identical to that described in the preceeding section for the coal-based plant. Major steps in the process are:

- Shift Reaction - The carbon monoxide is used to convert water to hydrogen over an Mo-Co sulfide catalyst.

  $$CO + H_2O \rightarrow CO_2 + H_2$$

- Heat Recovery - Thermal energy is recovered from hot process gas, leaving the shift converter in the form of steam and pre-heated boiler feedwater.

- Acid Gas Removal - Hydrogen sulfide and carbon dioxide are removed by a process such as the Rectisol, which uses methanol to absorb the gases and separate them into a CO_2 stream containing 5 ppm H_2S and a hydrogen sulfide-rich stream containing about 35% H_2S and 65% CO_2. As a pollution control measure, the hydrogen sulfide is converted to elemental sulfur in a Claus plant.

- Final Gas Purification - Small amounts of CO and CH_4 are removed from the gas by scrubbing with liquid nitrogen. Sufficient nitrogen is vaporized to produce a 3:1 hydrogen-to-nitrogen mixture in the purified gas.

- Compression and Synthesis - The hydrogen-nitrogen mixture is compressed to 2500-3500 psig and introduced into the synthesis loop where ammonia is catalytically formed as described earlier.

  $$3H_2 + N_2 \rightarrow 2NH_3$$

- Air Separation - An air separation plant is necessary to provide the oxygen and nitrogen used in the process.

There are two commercial versions of the oil gasification process which have been adequately proven in many refinery applications for hydrogen production so that they can be considered for ammonia plant use. One has been developed by Texaco, and the other by the Shell Oil Company. Both can operate at pressures ranging from atmospheric to over 1500 psi, the higher pressures being of interest for ammonia synthesis to minimize overall power consumption, and both can handle a wide range of feedstocks. The major differences between the two lie in the manner in which the gas is quenched and in the manner in which the soot is handled.

In the Shell process, a unique type of heat exchanger, designed to prevent soot deposition, is used to quench the gas and generate high pressure steam. The cooled gas is further quenched with water, then scrubbed to remove the soot. The water/carbon slurry is flashed to atmospheric pressure and mixed with fuel oil which agglomerates the carbon. The mixture is pelletized, separated from the water,and the pellets are mixed with the fuel oil feed to the burner-reactor. Thus, the carbon is recycled to extinction.

In the Texaco version, shown schematically in Figure IV-10, the hot burner gas is quenched by direct injection of water. A large part of the water is converted to steam which is needed in the shift conversion section of the plant. The latent heat of the surplus steam is recovered in the heat recovery section. It is also possible to use a heat exchanger for high-pressure steam generation and to quench the gas in the Texaco process, but this technique is not normally used if the gas is to be shifted to form hydrogen.

Most of the carbon is removed in the quench operation and the final traces are separated in a high-shear venturi scrubber. The sooty water is contacted with naphtha, which preferentially wets the carbon so that a decanter will produce a carbon-free water and a naphtha layer containing the carbon. The naphtha/carbon mixture is mixed with a part of the heavy oil feed and the naphtha is then distilled off for recycle leaving the carbon in the fuel oil. The oil/carbon mixture is normally recycled to the reactor, but can be burned as boiler fuel if low sulfur oil is used. Naphtha makeup is 0.1-0.2% of the total heavy oil feed to the process.

The water from the decanter is recycled to the scrubber but to prevent buildup of ash and soluble inorganic materials introduced as impurities in the heavy oil feed, a purge or blowdown is necessary.

b. Cost of Production

Based on a plant with a capacity of 1000 tons/stream day which would produce 340,000 tons of ammonia per year; a mid-west location; and March 1975 energy and fuel costs; the estimated cost of producing ammonia would be $106.15/ton, as shown in Table IV-25. Of this total cost, $70.36 (66%) represents the cost of energy inputs. About 48% of the cost is attributed to the feedstock itself, in this case a high sulfur residual oil. The other fuel and power inputs are needed to supply motive steam for turbine drives in the air separation plant and the ammonia plant and for pump drives.

Source: Texaco Development Corporation

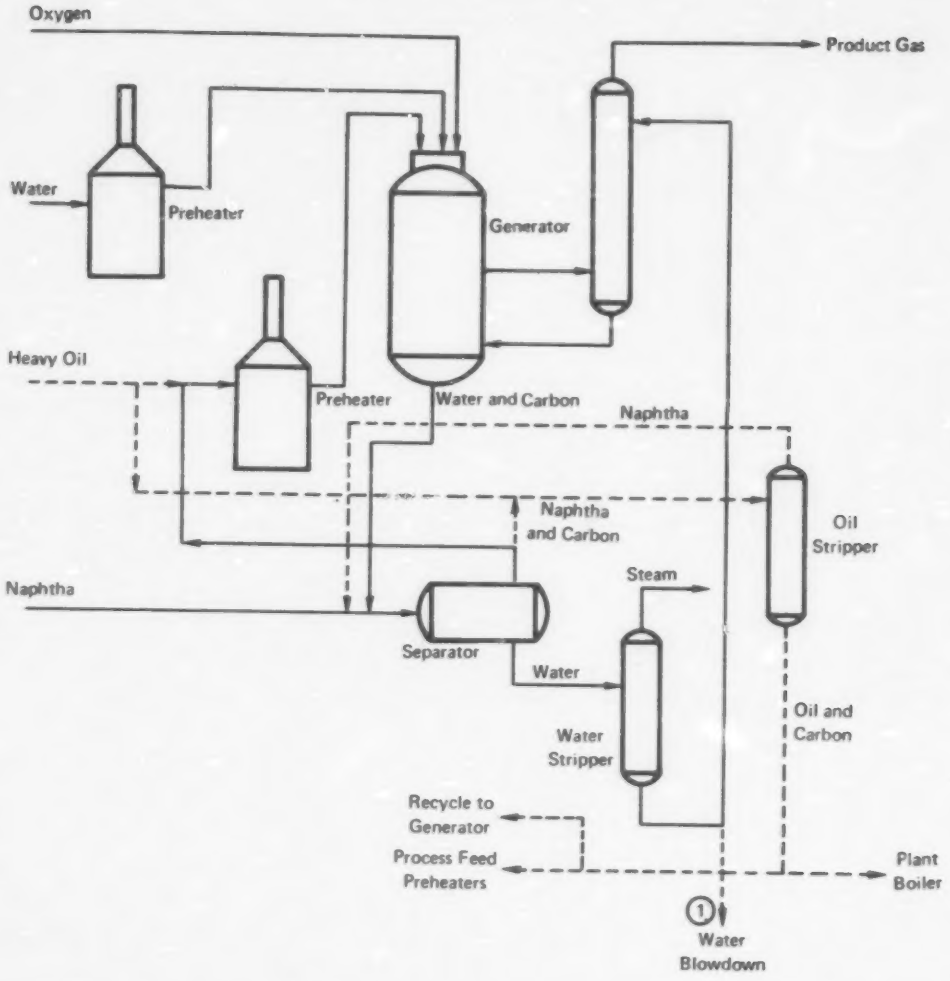

Figure IV-10. Synthesis Gas Generation Including Recovery of Unconverted Carbon

TABLE IV-25

ESTIMATED PRODUCTION COST OF AMMONIA FROM RESIDUAL FUEL OIL

Product: Ammonia Process: Partial Oxidation of Residual Fuel Oil Location: Mid-West

Annual/Design Capacity: 1000 ton /stream day Fixed Investment: $70,600,000

Annual Production: 340,000 tons Stream Days/Yr.: 340

	Units Used or Anual Basis	$/Unit	Units/Ton of NH_3	$/Ton NH_3
VARIABLE COSTS				
Residual Fuel Oil				
Feedstock (6.2%S)	Bbl	11.97[1]	4.27	51.11
Fuel, Low Sulfur	Bbl	15.12	1.08	16.33
Naptha	Gal	0.35	3.5	1.22
Power	Kwh	0.0165	103	1.70
Energy Subtotal				70.36
Catalysts & Chemicals				0.45
Cooling Water Circulation	thousands of gallons	0.03	76	2.28
Process Water	thousands of gallons	0.20	0.74	0.15
Total				73.24
SEMI-VARIABLE COSTS				
Operating Labor	28 men	$12,000/yr.		0.99
Supervision	4 foremen	$18,000/yr.		0.21
	1 superintendent	$25,000/yr.		0.07
Labor Overhead	35% of labor & supervision			0.45
Maintenance	4% of investment/yr			8.31
Total				10.03
FIXED COSTS				
Plant Overhead	70% of labor & supervision			0.89
Local Taxes & Insurance	1.5% of investment/yr			3.11
Depreciation	11 years, straight line			18.88
Total				22.88
TOTAL PRODUCTION COST				106.15
Return on Investment (Pretax)	20% of investment/yr			41.53
POLLUTION CONTROL				3.46
TOTAL				151.14

[1] Based on $1.90/million BTU for high sulfur fuel oil, $2.40 for low sulfur oil and 6.3 million Btu/bbl.

The makeup naphtha used for the soot removal cycle is considered as an energy input because this makeup replaces that left in the heavy oil sent to the reactor.

This process can take advantage of the lower cost of high sulfur residual oil, because (as part of the process) the hydrogen sulfide formed is removed in a form amenable to conversion to marketable sulfur in a Claus process plant. However, supplemental steam must be based on higher cost low sulfur oil, because removal of sulfur oxides from the stack gas of the boiler is not economically feasible with the current alternatives for this size unit. Consideration has been given to incorporating the flue gas into the Claus plant feed, but the dilution effects of the low sulfur oxide gas, combined with the power consumption of blowers, make this alternative uneconomical compared to purchasing low sulfur fuel.

c. Energy Usage

The total energy consumption of the process, expressed in equivalent British thermal units is 35.24 million Btu/ton of ammonia, as shown below:

		10^6 Btu/ton
Feedstock	4.27 bbl @ 6.3 x 10^6 Btu/bbl	26.90
Fuel	1.08 bbl @ 6.3 x 10^6 Btu/bbl	6.80
Naphtha	3.5 gal at 130,000 Btu/gal	0.46
Power	103 kWh @ 10,500 Btu/kWh	1.08
Total		35.24

The form of energy used can be varied considerably depending on the relative value of the energy forms and the cost of capital. For example, instead of using a boiler fired with low sulfur oil to generate steam for turbine drives, some turbines could be replaced with electric motors to the extent that essentially no fuel would be needed except for startup steam. Power consumption, of course, would increase drastically and total production costs would also increase, as would total energy, expressed as Btu, using 10,500 Btu as the fuel input to produce 1 kWh. The probable optimum situation is as developed above.

d. Effluent Controls Required for Heavy Oil Gasification Alternative

The schematic representation of the process considered here is shown in Figures IV-10, -11, -12, and -13. The nature of the pollutant emissions are summarized in Tables IV-26, IV-27, and IV-28.

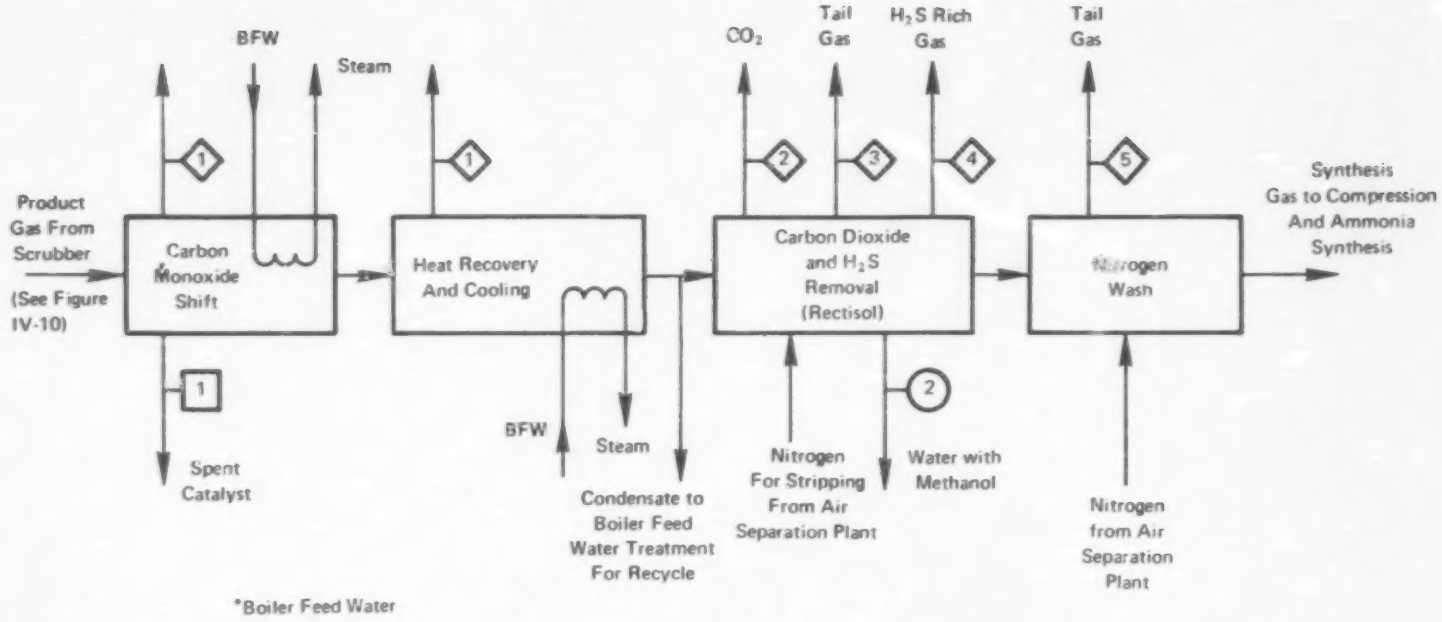

Figure IV-11. Carbon Monoxide Shift and Synthesis Gas Purification

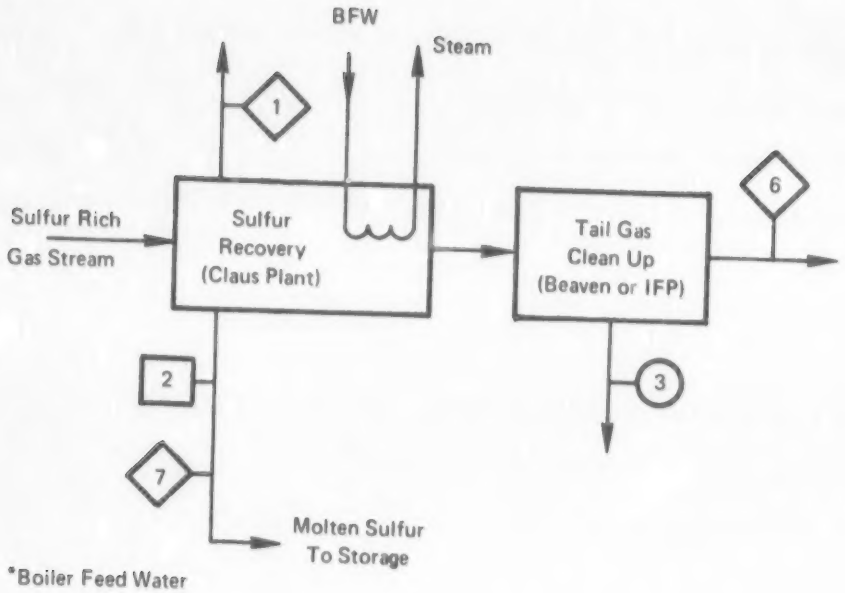

Figure IV-12. Sulfur Recovery

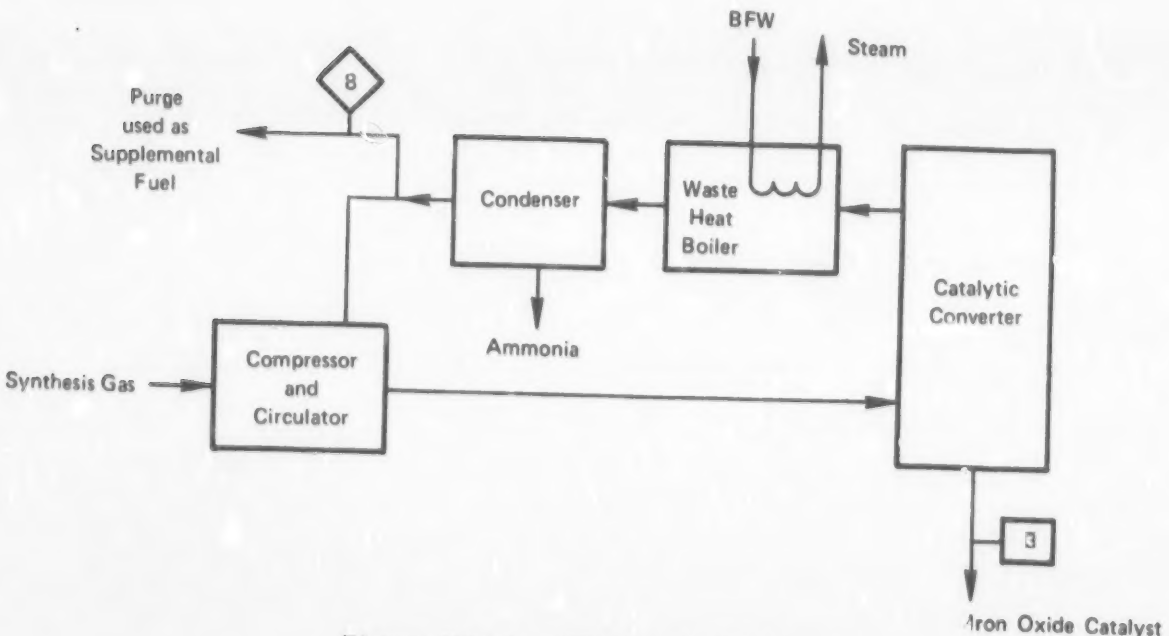

Figure IV-13. Ammonia Synthesis

TABLE IV-26

	WATER EFFLUENTS* - AMMONIA-FROM-HEAVY OIL ALTERNATIVE	Method of Handling
(1)	Soot recycle system purge	treated
(2)	Waste water from Rectisol unit	treated
(3)	Waste water from sulfur recovery plant tail-gas cleanup	treated

TABLE IV-27

	AIR EMISSIONS* - AMMONIA-FROM-HEAVY OIL ALTERNATIVE	Method of Handling
◇1	System vents for pressure let-down	infrequent; flared
◇2	Byproduct CO_2	potential for urea manufacture
◇3	Tail gas from Rectisol	vented
◇4	Sulfur-rich stream from Rectisol	to sulfur recovery
◇5	Tail gas from nitrogen wash	burned in boiler as supplemental fuel
◇6	Claus plant tail gas cleanup vent	vented
◇7	Byproduct molten sulfur (storage & transfer facilities)	marketed
◇8	Synthesis loop purge gas	burned as supplemental fuel

TABLE IV-28

	SOLID WASTES* - AMMONIA-FROM-HEAVY OIL ALTERNATIVE	Method of Handling
[1]	Catalyst from CO shift	recovered
[2]	Molten sulfur	marketed

*Keyed to Figures IV-10, 11, 12 and 13

The gasification of heavy oil results in the following changes in environmental input from those discussed in the corresponding section for the natural gas base case:

- A sulfur recovery plant will be required, though it will be somewhat smaller than the one for the coal alternative; and
- An additional wastewater stream, the soot recycle system blowdown, must be treated.

These specific changes are discussed below.

e. Environmental Effects Related to Water Pollution

The gasification of heavy oil can be compared to gasification of coal in the following ways:

- The synthesis gas purification system waste stream has the same flows and approximate characteristics;
- There is no runoff in the oil alternative; and
- The wastewater from the sulfur recovery process is about 70% of the flow from the coal unit.

In addition, the oil gasification unit must treat the purge from the soot recycle system. The characteristics of this stream are presented in Table IV-29.

The total wastewater load (gallons per day) for the oil alternative is:

Cooling Tower Blowdown	800,000
Rectisol Purge	10,000
Tail Gas Cleanup Purge	6,000
Soot Recycle System Purge	41,000

There would also be a wastewater load associated with the ammonia production unit. The stream is the same for all alternatives, so it has not been included in the comparison.

- Wastewater Treatment Technology - While the biochemical oxygen demand of the wastewater has not been determined, the wastewater contains biodegradable substances and can be subjected to biological treatment. Most likely, a treatment system quite similar to that used to treat the wastewater from the synthesis gas purification wastewater treatment in the coal gasification alternative could be employed. The treatment system would consist of:

TABLE IV-29

SOOT RECYCLE SYSTEM BLOWDOWN

Volume	41,000 gpd
Composition[1]	ppm
Ash	0.1
H_2S	25
TDS	5000
NH_3	300
Hydrocarbons	10
[1] Oil basis used	
Sulfur	6.2 percent
NaCl	30 ppm
Ash	200 ppm

Source: Schlinger, W.G. and Slater, W.L., Application of the Texaco Synthesis Gas Generation Process Using High Sulfur Residual Oils as Feedstock. Paper No. 1542, Texaco Inc., Montebello Research Laboratory, Montebello, California.

- A 24-hour equalization basin;
- A 15-day aerated lagoon;
- A 15-day non-aerated (anaerobic) lagoon; and
- A chemical feed system.

In the treatment process, ammonia would be removed by a combination of air stripping and biological oxidation to nitrate followed by denitrification. To effect denitrification, sufficient carbon must be present; so it is possible that supplementary methanol would have to be added to the non-aerated lagoon.

With proper operation, it should be possible to achieve a 90% removal of ammonia and hydrogen sulfide, thus producing an effluent containing 30 ppm ammonia and 2.5 ppm hydrogen sulfide.

- Wastewater Treatment Costs - Treatment costs are presented in Table IV-30.

TABLE IV-30

OIL GASIFICATION ALTERNATIVE
INCREMENTAL WASTEWATER TREATMENT COST ESTIMATES
(BASIS: 1000 TPD AMMONIA PRODUCTION)

	Synthesis Gas Purification System Wastewater	Soot Recycle System Blowdown	Total
CAPITAL INVESTMENT, $	$186,000	$350,000	$536,000
ANNUAL OPERATING COSTS			
INDIRECT COSTS			
Depreciation	16,900	31,800	48,700
Return on Investment (@ 20%)	37,200	70,000	107,200
Taxes and Insurance (@ 2%)	3,700	7,000	10,700
TOTAL INDIRECT COSTS	$57,800	$108,800	$166,600
DIRECT COSTS			
Operating Labor	14,700	16,500	31,200
Maintenance	7,100	14,000	21,100
Chemicals	800	2,500	3,300
Electric Power	5,400	13,900	19,300
Sludge Disposal	1,600	1,000	2,600
TOTAL DIRECT COSTS	$29,600	$47,900	$77,500
TOTAL ANNUAL COST	$87,400	$156,800	$244,200
UNIT COST, ($/Ton)	$0.26	$0.46	$0.72

SOURCE: ADL Estimates

f. Environmental Effects Relating to Air Pollution

The air pollution associated with oil gasification is less than that associated with coal in that there is no coal-related dust source. The only air emission of significance is the sulfur-laden exhaust from the carbon dioxide and hydrogen sulfide removal exhaust. The stream must be controlled using a sulfur recovery plant with a tail gas cleanup plant. The capital costs of the sulfur recovery process were shown in Figure IV-9. For an oil feedstock, the plant would produce about 42 tons of sulfur per day as opposed to 60 tpd produced with coal. The operating costs are shown in detail in Table IV-31. The resulting cost of $2.74/ton of ammonia is only slightly less than the cost of sulfur control relating to the coal alternative.

g. Environmental Effects Relating to Solid Waste Disposal

The wastewater treatment system will produce very little sludge because of the low quantity of BOD present. We estimate that less than 200 tons per year of wet sludge would be generated by the wastewater treatment plant. The cost of disposal is included in the wastewater treatment costs.

TABLE IV-31

SULFUR CONTROL COSTS FOR ACID GAS EXHAUST
OIL GASIFICATION ALTERNATIVE
(Basis: 1000 TPD of Ammonia, 42 long ton/day Sulfur)

CAPITAL COSTS, $1,000's	$3,050
ANNUAL OPERATING COST, $1,000's/Yr	
Indirect Operating Costs	
- Depreciation, 11 years	277
- Return on Investment (@ 20%)	610
- Insurance and Taxes (@ 2%)	61
TOTAL INDIRECT COSTS	$948
Direct Operating Costs	
- Labor	
Direct (@ $6.00/Hr, 1 Man/Shift)	50
Supervision (@ 15% of Labor)	7
Labor Overhead (@ 35% of Direct and Supervision)	20
Plant Overhead (@ 70% of Direct and Supervision)	39
- Maintenance (@ 5%)	153
- Utility	
Electric Power (@ 140 kWh/LT, $0.02/kWh)	40
Fuel (@ 0.08 10^6 Btu/LT, $2.00/$10^6$ Btu)	23
Cooling Water (@ 20,000 gal/LT, $0.03/$10^3$ gal)	8
- Chemicals (@ $2.50/LT in tailgas)	2
TOTAL DIRECT COSTS	$342
Byproduct Sulfur Credit (@ $25/LT, 42 LT/D)	(357)
TOTAL ANNUAL COST, $1,000's/Yr	$933
UNIT COST, $/ton NH_3	$2.74

SOURCE: ADL Estimates

V. IMPLICATIONS OF POTENTIAL INDUSTRY/PROCESS CHANGE

Several changes in practice will occur in ammonia manufacture due to both the shortage of natural gas and environmental regulations. These changes include the addition of air preheaters to new and existing ammonia plants to decrease fuel consumption; conversion from natural gas to fuel oil in firing ammonia reformers, boilers, and dryers; the separation of hydrogen from the purge gas in the ammonia synthesis loop; and the building of new ammonia plants based on petroleum or coal both for fuel and for feedstock. Of these, the only changes that meet the criteria of this study are the production of ammonia from coal or petroleum in new plants.

Ammonia manufacturers are among the largest energy users in the country. We estimate that in 1973, ammonia plants consumed 590 billion cubic feet of natural gas, or 2.4% of total U.S. natural gas use. Ammonia forms the basis for nearly all nitrogen fertilizers and is also used along with its derivatives for the manufacture of other basic nitrogenous chemicals. About 20% of the ammonia production is for non-fertilizer uses. In the United States, its manufacture depends on natural gas, both as a raw material and as a fuel.

The ammonia industry in the United States and worldwide has seen tremendous growth over the years. Output in 1973 was almost ten times that of 1950 for an average annual growth rate over the 23-year period of over 10% per year. This reflects almost exactly the growth rate in nitrogen fertilizers in the United States, which has had a dynamic long term growth.

The shortage of natural gas has contributed to the problems of the United States ammonia industry. While the gas shortage is a nationwide phenomenon, each gas pipeline or supplier has his own unique problems, and these problems are of differing severity. A Fertilizer Institute survey indicates that only 231,000 tons of ammonia production were lost because of gas cutbacks in fiscal year 1973/74; about 1.5% of total production capability. Today, however, several ammonia plants are closed because of the inability to get natural gas, and the situation is worsening.

While existing plants have been able to get gas supplies, it is difficult for a new plant to obtain gas. Unless natural gas can be made available, new plants to supply increased requirements in the future will have to use fuel oil or coal both for feedstock and for process heat. Many existing plants may have to convert their reformers to fire fuel oil. However, this latter change is a fuel switch and would not involve a change in the chemistry of the process, because gas would still be used as a feedstock. Basing new plants on liquid or solid feeds, however, implies new processes. Using fuel oil as a raw material for ammonia plants would require new technology for the United States. This technology is commonplace in other parts of the world, but not here. Similarly, the use of coal as a raw material for the manufacture

of ammonia will require new technology. There are a few coal-based ammonia plants in the world, but in the past coal-based plants generally have not been economical.

The use of fuel oil and coal for the manufacture of ammonia will require partial oxidation processes. These will require oxygen, which in turn will require large amounts of electric power. Associated with the generation of power is additional pollution. The fuels for electric power generation are significantly higher in sulfur than is natural gas, and it will be necessary to remove this sulfur. This in turn could imply increased sulfur contents of waste streams, either liquid or solid.

The use of coal as a feedstock will result in increased mining, transporting, and handling of coal, again with associated pollution problems. About 1.3 tons of coal are required per ton of ammonia.

An additional consideration in the manufacture of ammonia from coal would be the potential need to develop improved water pollution control technology if plants are to be located near western coal. Generally, they are located in arid areas where rivers and streams have less tolerance for pollutants. Thus, water pollution restrictions on ammonia plants located in the West may have to be even more severe than for those located in other parts of the country.

Western coal may not be a preferable starting material for ammonia plants because it is not near potential markets. Also, the ability of an ammonia plant to use high sulfur coal would encourage ammonia producers to use high sulfur coal because of its lower value. Nonetheless, low-sulfur western coals can be made available fairly cheaply, and they conceivably could be used as raw materials.

The alternates to natural gas, if arranged in order of capital investment and proven, reliable, processes, would be naphtha or LPG's, residual fuel oils, and (by most rankings, a very distant third) coal.

Naphtha and LPG's do not represent a viable alternate solution because of their very limited future incremental availability and high value for alternative uses, essentially the same situation as projected for natural gas. Also, the dramatic changes in the value of convenience energy place a different emphasis on the relative value of capital investment and associated charges. For example, with natural gas at $25¢/10^6$ Btu the cost of gas was 35 to 40% of the cost of ammonia. In the same plant with gas at $\$2.50/10^6$ Btu, it becomes 87% of the manufacturing cost. Thus, emphasis for low cost becomes centered on energy cost, not investment.

Estimates we have made of the probable cost of feedstocks in 1980 result in the following values for the upper Midwest:

	$/10^6$ Btu (HHV)
Natural Gas	2.90 - 3.00
Heavy Fuel Oil	2.50 - 2.60
High Sulfur Coal	0.60 - 1.50

This large difference in projected value between gas and oil, and coal, certainly justifies a careful consideration of coal as a feedstock for ammonia production.

A. AMMONIA FROM COAL

1. Impact on Pollution Control

The following additional emissions must be controlled when producing ammonia using coal feedstock:

- Water
  - Coal and slag pile runoff,
  - Wastewater from syngas purification processes;
- Air
  - Coal handling and grinding,
  - Sulfur-rich stream from syngas purification; and
- Solid
  - Slag,
  - Sulfur, and
  - Wastewater treatment sludge.

To control the above emissions, an additional $8.7 million is required in capital investment for a plant, equivalent to 8.6% additional investment (Table V-1). About 53% is related to control of runoff and the remainder to control of air emissions, the most significant cost being for the removal of sulfur from syngas purification emissions. Also associated with environmental control for the 1,000-ton-per-day plant are annual operating costs totalling $2.9 million ($8.65 per ton of ammonia). About 59% of these costs are for control of water effluents from runoff and, to a lesser degree, the synthesis gas purification processes. The air control costs are for coal handling emissions and recovery of sulfur from the syngas purification process. The costs associated with slag disposal are factored into the water cost as runoff control, assuming onsite disposal of the slag. This can be translated to an offsite disposal by using an estimated charge of $15 per ton of slag.

There will be no unique problems meeting the environmental standards which may be associated with producing ammonia from a coal feedstock. The difficulties are expected to be similar to those encountered in electric power generation and in industrial use of coal-fired boilers. In addition, because the quantities of coal required are large enough to justify location near an existing mine or the opening of a new mine, there will be the additional pollution aspects related to mining.

TABLE V-1

CAPITAL INVESTMENT SUMMARY FOR ENVIRONMENTAL CONTROL (Basis: 1000 TPD Ammonia Plant)

	Alternative Feedstock	
	Oil	Coal
Water Pollution Control Costs, $1000's		
Runoff Control and Treatment	-	4,429
Synthesis Gas Purification	186	200
Solids Purge	350	-
Total	536	4,629
Air Pollution Control Costs, $1000's		
Feedstock Handling	-	460
Synthesis Gas Production	3,050	3,600
Total	3,050	4,060
TOTAL ENVIRONMENTAL COSTS, $1000's	3,585	8,689

Source: ADL Estimates

TABLE V-2

ANNUAL INCREMENTAL OPERATING COST SUMMARY FOR ENVIRONMENTAL CONTROL (Basis: 1000 TPD Ammonia Plant)

	Alternative Feedstock	
	Oil	Coal
Water Pollution Control Costs, $1000's/yr		
Runoff Control and Treatment		1,649
Synthesis Gas Purification	87	96
Solid Purge	157	-
Total	244	1,745
Air Pollution Control Costs, $1000's/yr		
Feedstock Handling	-	185
Synthesis Gas Production	933	1010
Total	933	1195
TOTAL, $1000's/yr	1177	2,940
Unit Cost, $/ton of Ammonia	3.46	8.65

Source: ADL Estimates

2. Impact on Energy

In controlling the emissions from an ammonia plant based on coal, which are incremental to those for the same plant based on natural gas, 166 x 10^3 Btu per ton of ammonia are consumed. This amounts to approximately 56 billion Btu per year (Table V-3). This is only an increment of 0.5% over that needed for production. About 71% of the energy is in the form of electrical power (3.8 billion kWh/year).

Ammonia production has a significant energy requirement. The amount required for environmental control is an incremental 0.5%.

3. Factors Affecting Probability of Change

A few ammonia-from-coal plants have been built in the world, but further process improvements will be required before such plants can become viable for the United States. Significant environmental impact may be felt by the manufacture of ammonia from coal. Such plants would probably be located near coal mines and may in fact justify the opening of new mines. Because ammonia plants based on coal can normally use high sulfur coal, it would probably be to their advantage to do so. High sulfur coal (3-5%) will have an intrinsically lower value than low sulfur coal, and since it is possible to use the lower value material, ammonia producers probably would do so. This may result in the manufacture of significant quantities of byproduct sulfur but could alternatively result in sulfur discharges in the form of a solid waste stream. The cost of manufacturing ammonia from coal would also have to be competitive. Figure V-1 provides a comparison of the ammonia production costs for various coal and natural gas prices. Note that, until the price of natural gase reaches \$2.50/10^6 Btu and coal remains at \$0.95/10^6 Btu or less (\$17.20/ton), the new feedstock is not attractive unless there are overriding factors in a specific area -- such as the unavailability of natural gas.

The investment required for a coal-based plant is higher than that for one based on liquid or gaseous hydrocarbons. Nevertheless, when faced with a continuing shortage of natural gas, the industry will have to find other fuels and feedstocks. Thus, coal must be considerably cheaper on a Btu basis than competing fuels to make investment attractive. A plant constructed to handle coal can be switched to either natural gas or heavy oil essentially while on-stream, thus taking advantage of the price differentials among these fuels as they change from time to time. However, the penalties associated with the higher investment required for the coal-based plant will remain.

4. Areas of Research

Investigations are advisable to identify the path of the metals present in coal through the gasification process to determine their presence in the solid wastes such as slag, in the air and water emissions, and in process recycle streams.

TABLE V-3

ENERGY CONSUMPTION SUMMARY FOR ENVIRONMENTAL CONTROL

	Alternative Feedstock	
	Oil	Coal
Water Pollution Control		
Electric Power (10^6 kWh/yr)	.965	.705
Fuel (10^6 Btu/yr)	-	-
Total Fuel Equivalent @ 10,500 Btu/kWh	10,130	7,402
Air Pollution Control		
Electric Power (10^6 kWh/yr)	2.000	3.090
Fuel (10^6 Btu/yr)	11,500	16,500
Total Fuel Equivalent @ 10,500 Btu/kWh (10^6 Btu/yr)	32,500	48,945
TOTAL ELECTRIC POWER (10^6 kWh/yr)	2.965	3.795
TOTAL FUEL (10^6 Btu/yr)	11,500	16,500
TOTAL FUEL EQUIVALENT @ 10,500 Btu/kWh (10^6 Btu/yr)	42,630	58,347
Unit Energy Consumption (Btu/ton NH_3)	125,400	165,700

Source: Arthur D. Little, Inc. estimates.

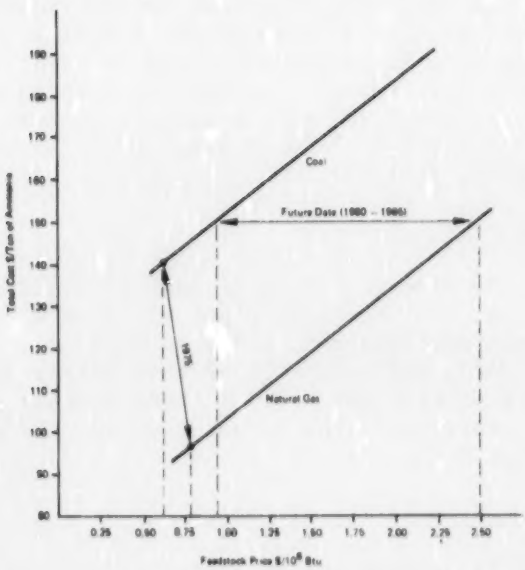

Figure V-1. Effect of Natural Gas and Coal Prices Upon Ammonia Prices

B. AMMONIA FROM PETROLEUM

1. Impact On Pollution Control

The following additional emmisions must be controlled when producing ammonia using oil feedstock:

- Water
  - Wastewater from syngas purification processes;
- Air
  - Sulfur-rich stream from syngas purification; and
- Solid
  - Sulfur, and
  - Wastewater treatment sludge.

To control the above emissions, an additional $3.6 million will be required in capital investment for plant, equivalent to 5.1% additional investment (Table V-1). About 85% of this additional investment is required for control of air emissions with the major portion required on the sulfur-rich exhaust from the syngas purification process. The annual operating costs associated with environmental control for the 1,000-ton-per-day plant are $1.2 million. About 79% of this annual cost is for control of sulfur emissions from the syngas purification process. The remainder is for treatment of wastewater streams from oil gasification and from syngas purification. These combined capital related and direct operating costs can be translated to $3.46 per ton of ammonia. No unique problems are expected in meeting the environmental standards which may be associated with producing ammonia from heavy fuel oil feedstock. The difficulties are expected to be similar to other industrial applications of residual fuel oil.

2. Impact on Energy

In controlling the emissions from an ammonia plant based on oil, which are incremental to those for the same plant based on natural gas, 125×10^3 Btu per ton of ammonia are consumed. This amounts to approximately 43 billion Btu per year (Table V-3), and about 72% of this energy is in the form of electrical power (3.0 million kWh/year). Since ammonia production has a significant energy requirement, the amount required for environmental control is only an incremental 0.2%.

3. Factors Affecting Probability of Change

This technology is commonplace in countries outside the western hemisphere but no plants in the United States produce ammonia from petroleum. New plants built to manufacture ammonia from petroleum will probably be based on the heavier petroleum fractions, because over the long term they will probably be less expensive than lighter fractions such as LPG and naphtha. There will

be environmental problems associated with these plants, however, technology already exists to overcome many of the problems. It remains only to translate this technology to specific applications.

The cost of manufacturing ammonia from petroleum would also have to be competitive. Figure V-2 provides a comparison of the ammonia production costs for various petroleum and natural gas prices. Note that, if the price of natural gas reaches $2.65/million Btu, residual fuel oil will be an attractive new feedstock if it is available for less than $2.00/million Btu.

4. Areas of Research

The process is well documented. Little research is required and the companies involved are pursuing those areas.

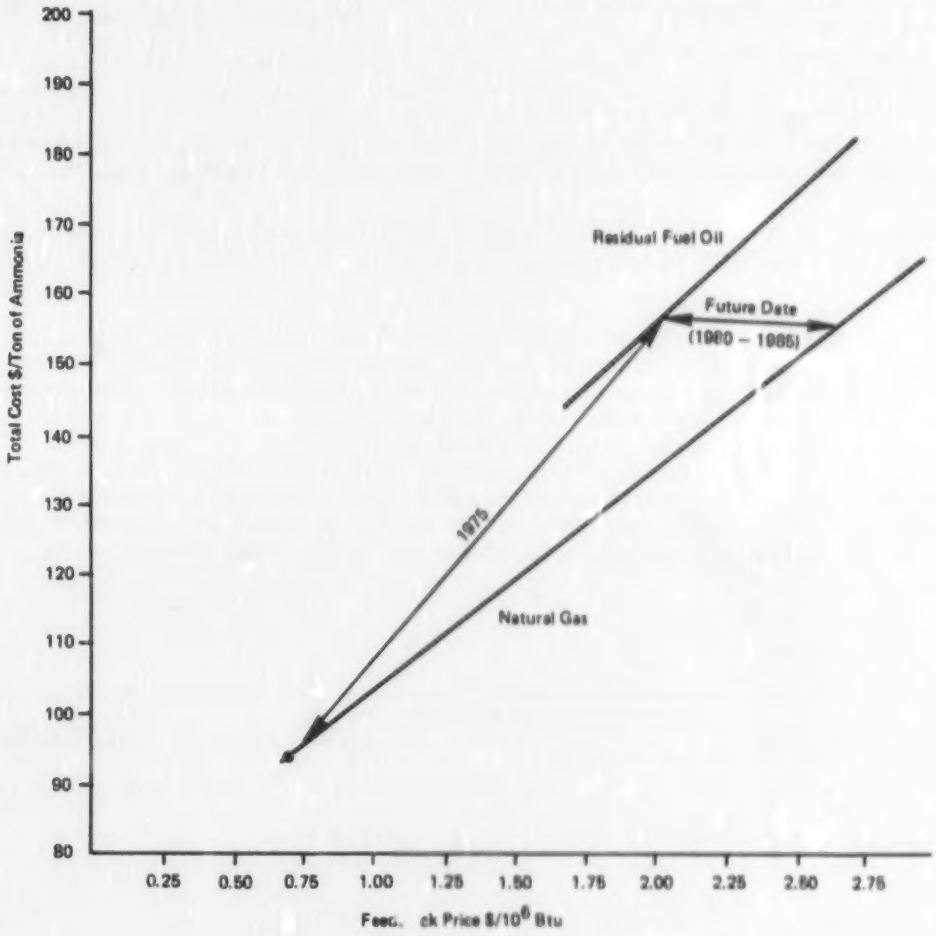

Figure V-2. Effect of Natural Gas and Residual Fuel Oil Prices Upon Ammonia Prices